INTEGRATED ENERGY POLICY REPORT COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

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In the Matter of:                  )
                                   )
Informational Proceeding and       ) Docket No.
Preparation of the 2004 Integrated) 03-IEP-01
Energy Policy Report (IEPR) Update)
                                   )
2004 Transmission Update           )
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CALIFORNIA ENERGY COMMISSION

1516 NINTH STREET

HEARING ROOM A

SACRAMENTO, CALIFORNIA

MONDAY, APRIL 5, 2004

9:34 A.M.

Reported by:
Peter Petty
Contract No. 150-01-005

COMMISSIONERS PRESENT

John Geesman, Presiding Member

James Boyd, Associate Member

ADVISORS PRESENT

Michael Smith

Christopher Tooker

STAFF and CONSULS PRESENT

Kevin Kennedy

Kristy Chew

Don Kondoleon

Judy Grau

ALSO PRESENT

Joe Eto
Consortium of Electric Reliability Technology
Solutions; Lawrence Berkeley National Laboratory

Barry Flynn
Flynn RCI

David Korinek
San Diego Gas and Electric Company
Sempra Energy

Gary L. DeShazo, Manager
California Independent System Operator

Kevin J. Dasso, Director
Pacific Gas and Electric Company

Patricia Arons
Southern California Edison Company

Morteza Sabet
Western Area Power Administration

ALSO PRESENT

Mark Ward
Los Angeles Department of Water and Power

James Feider
Transmission Agency of Northern California

Jane Hughes Turnbull, Principal
Peninsula Energy Partners
League of Women Voters

Jane Bergen
League of Women Voters

Andrew Bozeman
SSCDC

Francisco DaCosta
Environmental Justice Association

Bill Myers
The Valley Group

Rich Ferguson
Center for Energy Efficiency and Renewable Technologies

Tom Tanton
Vulcan Power; Silvan Power
Pacific Southwest Combined Heat and Power Initiative

Perry Cole
Trans-Elect

Bulant Bilir
Solargenix

Hal Romanowitz
Oak Creek Energy

Kerry Hattevik
California Public Utilities Commission

Robert L. Sims
SeaWest

ALSO PRESENT

Mark D. Galperin
Controllable Electric Reactors Consortium
(CERC)

Richard E. Hammond
Optimal Technologies (USA), Inc.

Osa L. Armi, Attorney
Shute, Mihaly and Weinberger, LLP
Save Southwest Riverside County

Juan C. Sandoval
Imperial Irrigation District

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P R O C E E D I N G S

9:34 a.m.

PRESIDING MEMBER GEESMAN: This is a Committee workshop for the Commission's 2004 IEPR update. I'm John Geesman, the Presiding Member of the Commission's IEPR Committee. To my left is Commissioner Boyd, the Associate Member. The 2004 update is an extension, or rather a followup to the 2003 Integrated Energy Policy Report that the Commission adopted in November.

Those of you familiar with the 2003 report will remember that the report identified several issues meriting more detailed followup in 2004. The 2003 report brought forward the importance of modernizing and upgrading the bulk transmission grid. It identified both planning and permitting actions that the state should take to optimize the grid in a cost effectiveness, environmentally sensitive manner that will insure a reliable and robust system in the future.

The 2004 update process actually began in November 2003 when we held a workshop to identify key transmission planning issues, including how to best capture the strategic benefits of transmission assets.

Today's workshop is the second formal event of the update process relating to transmission. We've got several goals for today's workshop. One is to discuss long-range transmission system interconnection needs under various scenarios.

A second is to begin a stakeholder-driven process for the development of a long-range transmission system vision. And a third is to understand the transmission problems of immediate concern; critical short-range projects to address those concerns; and the consequences of delays in bringing them online.

We're currently planning two more workshops on other critical transmission planning and permitting topics. The first will be on May 10th where we'll discuss staff's corridor viability study, which is intended to identify the potential for expanding existing utility transmission corridors.

That workshop will also discuss the results of our consultant study quantifying the strategic benefits of transmission assets. We'll also continue the discussion of a long-term vision for California's transmission system and examine options for accelerating the development of renewables in the Tehachapi area.

We've tentatively planned another workshop for June 8th. And that day may move around a bit. At that workshop we'll describe how alternatives to transmission projects are currently addressed in planning and permitting processes; and how best to analyze alternatives in the future. That's an important CEQA issue, and it's been an issue that FERC has raised several times with respect to federal planning.

Staff will then produce a transmission white paper at some point in July. The Committee intends to hold workshops and/or hearings on the staff white paper in August. And we're likely to publish a Committee report in mid-September that will then be the subject of hearings or workshops in the fall.

The Commission is likely to adopt the 2004 IEPR update by November 1, 2004.

With that, why don't we commence. Kevin.

MR. KENNEDY: Good morning. My name is Kevin Kennedy, and I'm the overall project manager for Energy Commission Staff for the 2004 IEPR update and the 2005 IEPR. I want to welcome everyone here today and everyone listening on our webcast.

Just a couple of very quick housekeeping sort of details. For those of you who are here who are not particularly familiar with our building, just want to point out that there's a coffee and snack shop upstairs. Just go up the main stairs, sort of straight ahead that way. There are also bathrooms, water fountain and phones over in the far corner, sort of back out the doors and to the left.

Commissioner Geesman gave a very good introduction to the overall process so I won't do any of that today. We do have a very full schedule, so from here I'll just hand it over -- actually, some quick introductions. Kristy Chew is acting as project manager for staff on the transmission update portion of the project. A couple of the key staff members here at the Energy Commission working on this are Don Kondoleon and Judy Grau. A number of other staff members are here in the audience, and we have a lot of folks who are doing a lot of good work.

One of the folks that has been helping

us on this is Joe Eto. And I'm going to go ahead and hand it over to him as the first speaker of the morning. Thank you.

MR. ETO: Thank you very much. My name is Joe Eto. I'm a Staff Scientist at the Lawrence Berkeley National Laboratory. I spend most of my time managing the program office for the Consortium for Electric Reliability Technology Solutions.

The Consortium is a group of national laboratories, universities and private sector participants that is conducting public interest energy research in the area of electricity reliability. We are currently performing work for the Department of Energy's transmission reliability program, and also for the California Energy Commission's PIER program.

And it's in that capacity that I have the pleasure to speak with you today about some work that we've been conducting through one of my partners, the Electric Power Group, looking at input for consideration by the Committee as it goes into this IEPR process.

What I'll be talking about today is the second of three products that we've been developing for the Commission. The first one was a review, an assessment of California's historic transmission assets, and an assessment of the benefits that they've brought to the state. And that was the subject of a Committee workshop back in November.

This second piece of work is going forward looking at alternative scenarios for transmission planning as a way of setting a context for some of the discussions that you'll be conducting through the IEPR process.

We have a third piece that will be featured at a future Committee workshop looking at application of some new methods to try to begin capturing some of the strategic values of transmission and reflecting them in some of the decision-making processes that go toward reviewing and approving transmission projects.

So let me try to motivate this talk a little bit and why we are here today. California currently has about 18.2 gigawatts of import capability over its transmission system. That's really about a third of our state's peak demand. So you can see immediately that transmission is a vital part of the electricity delivery infrastructure of this state.

But transmission, compared to generation or demand side alternatives, is somewhat unique asset, both in terms of its strategic value, and also in terms of its long-term nature. It takes a long time to plan transmission. And that timing is, at this point, somewhat inconsistent with the way in which resource planning is being done in the state.

One of, I think, the sad aspects of restructuring in our state has been essentially the di-integration of the generation and transmission planning process. So where you once had a forum where the kinds of timelines required to build projects could be harmonized and the tradeoffs assessed, you now have a de-integrated process, where a very long-lived asset, transmission, is hardly ever considered in the context of resource planning that is now geared toward, quote, "more of a market orientation" in which the lead time for projects, generation projects, is on the order of three to five years.

The sort of motivation behind the kind of scenario work we're doing is to really make the case that unless these planning horizons can be harmonized, and they're currently not harmonized, we're going to lead to the outcomes in which no transmission gets built.

And one of the down sides of that is that we're going to foreclose options that may be strategically of great importance to our state simply because we don't have fora and means by which we can trade off all the resources that are available to California in meeting its future energy needs.

And so it's in this context that we've undertaken a scenario analysis, very long-term in nature, to try to begin setting a stage for having some discussions in which transmission, along with all the other appropriate resource alternatives, can be considered in a comprehensive fashion.

So, why are we doing scenario analysis? I think the simplest statement is that the future is uncertain. Scenarios are stories about the future. They are a very understandable way to deal with and treat uncertainty explicitly. They're an approach toward trying to posit logically consistent future states of the world and assess what might be required under each of those states of the world from a resource planning perspective.

I want to emphasize that they've not a prediction, and they're not a policy preference. They're really a framework for having a discussion which I think is sorely needed in California about what is our long-term energy strategy; how will we plan for our long-term energy future.

So, what I'll be showing to you is not the result of thousands of monte carlo simulations, hundreds and thousands of production cost runs and power flow simulations. Instead, it's a very very simple exercise; going to rely on addition and subtraction to put together the building blocks of a resource plan looking at the future as a way of dimensioning some of the issues that we have to start grappling with in a systematic and comprehensive basis.

So the steps of this analysis are to begin first by looking at alternative resource, electricity demands in the year 2030. Look at the supplies that we might still have available from our existing asset base to meet those demands. And then look at what would be the requirements for imports under those likely assessments of the future instate resources that might be available to us.

Again, because this is an exercise in looking at uncertainty in an explicit fashion, we look at some alternative scenarios. And again, look at the resource implication, the import implications that arise from those different types of scenarios.

So, again, I want to just emphasize I don't have a preference for any one of these specific scenarios, but I think just running these numbers, getting our arms around this problem, looking at some consistent sets of assumptions are really going to assist us in this dialogue that we need to have about transmission planning in this state.

So, at the end of the scenario presentation I'll actually outline some of the policy issues and recommendations that we have for trying to take this type of analysis and move forward with it into the planning process.

Step One. How much electricity do we need. Clearly we have one of the most populous states in the nation. Population growth is going to continue. Looking at the U.S. Bureau of Census we estimate that by 2030 there will be 53 million people in the state who want energy services in some capacity.

Looking at projecting peak demand growth at a very conservative assumption, and we will look at an alternative here of 1.5 percent peak demand growth by 2030 we go from 52 gigawatts today to 80 gigawatts. We assume now a very conservative planning reserve margin of 15 percent. And you end up with a resource requirement of 92 gigawatts by the year 2030. This is a very important number. We'll do some sensitivities around this, but this really drives the analysis. This is the need that we will be trying to meet with a combination of resources, demand, supply and imports in the scenarios that I'll be presenting to you.

Step Two. What do we have of our existing resource base that would be available by 2030 to continue to supply those needs? So here is an assessment of our instate installed capacity of about 60 gigawatts. And you see that it's principally gas and oil. When you add the cogen it goes up to over 50 percent dependence on fossil fuels in that. Right now renewables, coal and nuclear are less than 10 percent each of that resource contribution. So that's a snapshot of where we are today.

Now, what I want to do is turn the table forward and start thinking about what this resource base might look like in 2030.

The first thing we need to do is recognize that we have a very large aging fleet of power plants in our state. Most of the plants were built prior to 1980; in fact, 60 percent were built prior to 1980. Most plants are generally assumed to have an economic life of about 30 years; but through repowering and refurbishment you can often extend the life of power plants.

For the purpose of this analysis we're going to make the following assumptions about power plant retirements. We're going to assume that the fossil fueled power plants will retire when they each reach 50 years of age. That the nuclear plants will be assumed to retire after one plant relicense for a life span of 40 years. And that hydro renewables will continue to operate at their current installed capacity.

These are topics i know that are subject of another IEPR workshop and I'm not here to debate where the Commission has gone on that.

This is really just a starting point for an analysis that we started last November. But it really gives you a ballpark, again, about what kind of installed capacity base you can count on in 2030, looking forward.

So looking forward, assuming all of those retirements, we look at the following resource base of about down from 60 gigawatts down to 32 gigawatts; principally hydro, cogen, renewables and gas. And it's upon this resource base that we're going to rebuild that stack back up to that 92 gigawatt requirement.

Here is just a summary of how we get to those retirements, starting from an installed base of 60 gigawatts today; retiring fossil fuel plants at about 23 gigawatts; and then the nuclear plants at 5.4 gigawatts. So now we're down to 32 gigawatts out of a need of 92 gigawatts.

What this says at the onset is that we're going to be looking at trying to build capacity or acquire capacity of on the order of 60 gigawatts between now and 2030 under the framework of this scenario as outlined.

What we have done here, just to summarize, is exactly that subtraction I described. On the left-hand side we see the 80 gigawatts of requirements, the 15 percent reserve margin getting us to 92 gigawatts. Subtracting what we currently will have left at -- of 32 gigawatts, creating a resource need of about 60 gigawatts.

Like I said, this is not the result of sophisticated production cost modeling. This is just addition and subtraction. But I think it's very useful to keep these gross numbers in mind, because these are the kinds of tradeoffs that we need to be thinking about as a starting point for these kinds of discussions.

Let's talk now about my basecase scenario. Most of these things I've spoke to, but I want to just point out a couple of things that we're going to use in the assumptions that we do to develop the import capability requirements.

I really want to just focus on a few of these assumptions here. The first assumption that we're going to make, consistent with the current version of the RPS, is that 20 percent of our capacity will come from renewable resources, of our energy will come from renewable resources. We're going to do a translation of those energy requirements into capacity, and I'll talk about that in a little bit.

We're going to also make an assumption that about 25 percent of our needs will be satisfied by imports. That's roughly consistent with the current amount that we import on peak right now. To say we can import a total of about 18 gigawatts, which is about a third. We can never import all that simultaneously. So, for the purposes of this exercise, I'm going to assume about 25 percent.

And so when you get to that and you assume you can't import it all at once, you end up with transmission interconnection requirements of about 26 gigawatts. And that's the number that we're going to start walking through in these next few slides.

So the first thing I want to do is build up from the existing base that we assume to be available in 2030, looking at the projects that are already approved or under review at the CEC, looking at their energy facility status report from last August. The CEC already approved projects of about 10 gigawatts. Projects under review. And then we do a translation of the 20 percent energy requirements for renewables to look at a net requirement for about 14 additional gigawatts of renewable energy, which leaves us with a shortfall here to meet this instate requirement of about 6 gigawatts of unidentified, and we'll assume for the minute, gas resources. Again, this is just the building blocks of what's on the books that we assume will get built and will be needed to meet the instate requirement.

COMMISSIONER BOYD: Mr. Eto, before you get too far away from the basecase could I ask you a question? What role for conservation did you include in your estimates of the future portfolio?

MR. ETO: In this initial setup of basecase analyses we're assuming that it's embedded directly in the assumption about load growth being at 1.5 percent per peak demand per year.

COMMISSIONER BOYD: Okay.

MR. ETO: Which is lower than the national projection of 1.8 percent. So there's some offset in peak demand requirements built into that. And then I'll talk with you about the specific alternative scenario which we assumed an even lower growth rate.

COMMISSIONER BOYD: Thank you.

PRESIDING MEMBER GEESMAN: Do you happen to know what our population growth rate is?

MR. ETO: The population growth rate that's underlying the work that we're doing is a little bit more than 1 percent.

PRESIDING MEMBER GEESMAN: Thanks.

MR. ETO: But, again, we're taking this directly off the U.S. Bureau of Census.

One of the values of not using, you know, I'm an analyst by heart, so I like the sophisticated models, but one of the real values of using these very simple stylized examples, it's very easy to change very fundamental assumptions and look at where you're at. And I think that's the kind of discussion that we need to have. And so I appreciate your comments about where those assumptions are coming from.

This is just a very quick summary of our current import capability, looking at the different lines. You know, we have about 8 gigawatts coming from the north; about 2 coming from Utah; the desert southwest, you know, 4.7 gigawatts on the north side, and then 2.8 in the southern region; and then in a modest interconnection to Baja of about .8 gigawatts.

These are some of the projects that are being discussed right now. This is the Devers-Palo Verde Number Two, expanding the interconnections with Mexico and increasing capacity to Wyoming. At this point, just for the purpose of discussion, we're assuming that these projects are under discussion will, in fact, get built and will reduce the need for additional transmission capability in the analysis that I'll be showing to you.

So let's do that. So what I show now is here's the current import capability from the different directions that we can bring power into our state. Here are some of the options that were currently under discussion that were listed on the table that I just showed you.

And so in order to meet what we assume to be our transmission import requirement of about 26.5 gigawatts, we're going to need an additional 4.1 gigawatts of transmission capability coming into the state.

For the purposes of this exercise we made an assumption that we would not bringing that in from the Northwest. But instead will be extending existing paths that are under discussion right now for expansion. So, again, this is going to the desert southwest, the inland northwest, and then also Mexico.

But, again, this is a discussion; this is not a prediction. This is just an effort to try to begin to frame the kind of resource need, the kind of import capability that would be required if you follow the assumptions that we've gone through to date about what demand is going to be, what instate resources are going to be.

For example, we're making an assumption that you'll meet the RPS requirement entirely with instate resources. Obviously if you change that, based on the registry, you might pick up some of that out of state. And that, again, would put another burden on the transmission import capability requirement.

So, because we've made a number of these assumptions we also did some sensitivity cases to try to bound what was realistic here. So, in the basecase we assumed peak demand growth of 1.5 percent; renewables at 20 percent; imports at roughly 25 percent.

So we looked at a couple of alternative

scenarios. This was before some of the discussions in the Legislature, but we made an assumption back in the fall that we could look at a scenario which would increase renewables to 33 percent. We made a low load growth assumption, which could be consistent either with the downturn of the economics or more aggressive conservation load management types of activities to reduce load to 1 percent growth. And then also one in which we assumed higher imports looking at 30 percent import target rather than a 25 percent import target, consistent with current experience.

This is a summary of what we get when you make all of those assumptions. And I think I want to just focus on a few numbers here. So here's our current situation here, across the top. We're importing about 18.2 gigawatts of capability here. The basecase that I just reviewed for you at 26.5 gigawatts, under the higher renewables essentially what we're doing is we're increasing renewables instate and displacing the need for instate generation from gas. And so the import requirement remains essentially fixed under this scenario.

Under the low load growth scenario you

do see a reduction in the import requirements going down to 24 gigawatts, down from 26. In the higher imports, of course, you see an increase going up to 31, 32 gigawatts of import requirement.

This, we submit, bounds a range, a range of discussion that we need to have about how plausible these scenarios are; what would be required from the standpoint of transmission planning if we were to go with any one of these scenarios in the infrastructure and capability of building that we need to think about as part of our planning activities.

How am I dong on time? Okay. Let me briefly just review, then, from the scenarios, themselves, what they imply for some of the non-transmission aspects of them.

In terms of generation capacity what we see here is essentially that the renewables cases I've just mentioned were essentially displacing gas-fired generation with higher renewables, or that renewables scenario. Under both the low load and higher import scenarios essentially this trading off where the power is coming from, whether it be imported or whether it be just reduced need all together because of a lower demand growth scenario.

The gas fuel requirements largely follow the gas capacity requirements; nothing surprising here. Here's the renewable capacity of the different assumptions. Here is the current installed capacity, about 4.5 gigawatts -- there's actually 10,000 gigawatts installed, but for the purpose of this exercise we're looking at a capacity factor of about 50 percent really.

And then in our basecase we're making the assumption that we would need 18 gigawatts of renewables, clearly in the high renewable requirement case a greater share would have to come from renewables. Low load would reduce the percentage upon which the 20 percent would be applied to. And higher imports really largely just displaces the gas, again. So you get something back close to the basecase without changing the renewable requirement, per se.

From the standpoint of transmission planning here is the implication that I think that we want to be focused on, which is here we have our current import capability and the additional import capability that we would require in each of the scenarios. And you see that's quite a range. Ranging from a low of about 6 gigawatts under the low load scenario, and that would be a net of about 2, in addition to what's already being talked about in terms of those three interconnections that I described earlier, up to a high of almost 14 gigawatts. So, again, this is an attempt to begin to bound the range of the kinds of transmission additions for interconnection that we should begin thinking about now if we're going to sort of meet these resource requirements under the types of scenarios that we've been describing here in this presentation.

So that said, we have a number of recommendations in areas that we hope this Committee will take up in its deliberations in thinking about transmission planning going forward.

I think the first thing that I want to stress again is that transmission planning is a very long-term prospect. And at root what we need to do is to begin to develop a robust planning process under which that long-time horizon that's associated with this asset can be considered on a comparable basis with the current planning horizons that are focused on much more shorter lead time kinds of resources. In order to have the tradeoff we need to have a consistent time horizon for all of those and be able to trade them off in an equitable fashion.

Part of the work that we did earlier was to focus on again making sure that when you do think about transmission you think about all of transmission. And in the last presentation I made for this Committee we talked about some of the strategic benefits that transmission has already had for the State of California, and as a real need to take those into consideration in an explicit fashion as we think about the role that transmission might have in the future.

At root I think what we're pointing to is the need for a statewide perspective, a statewide strategic and long-term perspective, looking at interconnection; using it as a basis for interaction with our regional partners; looking at it as a flow down into the current processes that we have as an overlay, as a template, as it were, to guide some of the discussions that are currently taking place. And a need to sort of integrate those into a consistent process.

Specifically we believe that there is a role for essentially having two parts to this process. One, a longer term strategic process; and the second the permitting process. Right now we have essentially part of the last one, but not at all anything of the first one. That was really what we lost with restructuring was the ability to sort of begin trading off, as a state, generation, transmission and demand side alternatives in a consistent fashion.

I think, you know, what drives me at the root of this is that, you know, this is a very strategic asset. If you don't take action now you effectively foreclose options that you may want to take advantage of later on. And that's really kind of the option value that I think we need to start thinking about in a more explicit fashion in the context of transmission.

And there's a lot of things that can be done. Site banking would be a good example. Corridor planning. These are very low cost entry options that give you the opportunity later on to develop transmission. But if you don't take them now you're going to find out the hard way later on if you really want to build it in a hurry that you can't do that.

Specifically to this two-part process that we're advocating, we believe that there is a real need for a long-run strategic phase of this planning activity that looks far beyond the five- and ten-year plans of the IOUs and the ISO right now. Looking at 25-year planning horizon consistent with the kinds of things that we've talked with you about in the scenario planning activity.

I think it's really important to sort of have a consensus built around that long-run vision of the resource portfolio for the state because it's going to help us guide into the processes that we're going to need to develop a consensus around some of the specific interconnections that we need to start planning for and developing right now.

Part of that will require assessing long-run resource potential; looking at the market hubs; and sort of integrating that into our shorter range planning for the specific interconnection projects that we might consider.

And I think it really also provides a way and a form and a venue to build consensus with our neighbors, will be critical to advancing these types of plans.

On the other flip side, the permitting process, you know, is currently focused on very specific projects. But they should flow out of the strategic vision. They should be sort of a handoff into those. That process, itself, needs to be streamlined and harmonized from a statewide perspective. And also needs to have incorporated valuation methodologies that begin to address the strategic and insurance value of transmission.

So, to summarize, I'll go back to some of the things I started out with earlier. Transmission is a critical asset, a critical part of our electricity infrastructure in the state. I can't imagine a resource planning activity going forward without taking adequate consideration of it. Current approaches that we have for doing that are quite limited because they're not really well geared to the long lead time required to build transmission. And they also haven't historically considered some of the strategic values that transmission has brought and could bring in the future, which need to be considered if you're going to have a fair tradeoff of all the alternatives.

And I think that unless we're able to harmonize some of these processes we're going to end up with where we're at today, which is a very short-term focus, which essentially means that none of these long-term options will be considered, and will foreclose the opportunities to have the transmission that we might require in the future if we don't take those actions today.

With that, I look forward to your comments, and I close my prepared remarks.

MR. KENNEDY: How do you want to handle question and answer? Just take them?

PRESIDING MEMBER GEESMAN: Why don't we just open it up to the audience for your comments or questions. And I'll start by thanking you again, Joe. That very, I think, astutely has framed the issues that the state confronts. And this is a difficult process because it's often challenging to find consensus. But I think what you have done is tried to lay out the different consequences that we face if we're not able to establish some consensus as to what our guiding light should be going forward.

I'm a little bit befuddled by how we articulate or establish, in the process of either regulations or statutes, criteria that enough of the stakeholders buy off on to allow us to establish long-term objectives. That's one of the things that government has a hard time doing.

I think the way in which we make decisions now intrinsically forces us into a short-term perspective, which ends up, I think, leaving all of us much worse off when problems come up. Be they the 2001 blackouts that could have been greatly mitigated by the development of the Path 15 upgrade years before. Or the intellectual cul-de-sac we find ourselves in on the Valley Rainbow project, where our traditional tools guide us to a five-year planning horizon for a facility that has an estimated life, I think conservatively, of 50 years. But if you look at the primary asset as the corridor, I would wager quite a bit longer than 50 years.

These are problems that if the state is going to accommodate the population growth, which we seem to have no ability constitutional or otherwise to forestall, these are problems we need to confront and need to confront now while we do have the possibility perhaps of establishing some consensus.

So I would encourage members of the audience to step up and share your thoughts with us. And if you would identify yourself; and after you're done, leave a business card, if you have one, with the court reporter that would be helpful.

MR. SIMS: Robert Sims with SeaWest Wind Power. I'm trying to understand what your assumptions were as far as the 32 gigawatts of projects that are to be retired at reaching their 50 years of useful life.

It appeared that you were proposing that those would be replaced by out-of-state generators. It would seem like it would be very cost effectiveness to utilize those existing sites for state-of-the-art plants that would utilize the fuel infrastructure, the transmission infrastructure, the emissions that have been accepted in those areas. And that really retirement of units wouldn't really seem to be that valid. More of a replacement with state-of-the-art, perhaps even larger, facilities on the same sites.

MR. ETO: If I gave that impression I misspoke. What we did was we made an assumption that the plants, themselves, would retire after 50 years. And then we turned and looked at the CEC's own inventory of the current status of projects. And we made an assumption that those projects that have been approved will be built. Those that are under review and have been announced will be built. And that those would all be built instate.

We were silent on the location of where those would be built. Many of them have sites that have already been announced. And we also identified -- some additional instate generation, about 6 gigawatts of generation, which for the purposes of this exercise we didn't make an assumption at all about where they would be built, other than that they would be built instate.

So there was a real effort here to meet a certain instate requirement for power of about 69 gigawatts, which is about 75 percent of the projected need for 2030. And that goes back to kind of a historic alliance on imports for about 25 percent at peak times.

So, that's where that comes from. And

I'm sorry if I created the impression that it was retirement and building at some other location because that certainly was not the intent.

MR. SIMS: It would seem like an important part of the exercise would be to understand the cost of additional transmission infrastructure versus, you know, the siting and location of the new projects.

MR. ETO: Absolutely. I mean I think -- the point here, though, and again I think this goes to the Commissioner's early comment, is we need some common ground about what is the future resource vision of this state. And putting these numbers up in very gross terms that are very easy to debate and discuss what the alternatives might be, but do it in a consistent fashion, is a first step toward that.

So, I think this is where you start. You can look at different scenarios that have higher imports and lower imports, more renewables, less renewables. But until you get that sort of common view about, you know, this is the energy picture that we're looking at 25 years from now, it's very difficult to work backwards into what does that mean in terms of this project, that project, or the other project.

And I think the problem right now is we're starting with this project, that project, the other project, and we don't have a real basis for where does that fit in the larger portfolio. And that's why there's differences of opinion about where that could go, or how far that could go.

I think Commissioner Boyd's comment about energy efficiency is right on target. How does that fit in there. So we put in this low load scenario. If you can think of a scenario where efficiency could eliminate, you can put that in there. You have a basis for trading these things off in a consistent fashion, and running the numbers and seeing what the direct implication might be for imports, for instate resources, for instate renewables, et cetera.

But without that, it's just, you know, everybody, well, I think we can do it all with renewables, I think we can do it all with distributed generation, I think we can do it all with instate. We can't do those things. But you just sort of have a -- we have to start from the same set of assumptions and work logically through the numbers. And I submit you don't need lots of production cost models to do some of these basic calculations.

MR. KORINEK: Dave Korinek, San Diego Gas and Electric. We appreciate the information that the Commission has provided and the numbers that have been teed up for discussion. It provides a good framework to continue from this point.

One number I'd like to comment on is the report's 800 megawatt figure for increasing the Mexico to California transmission capacity. That's a doubling of the capacity according to the report. And the correct capacity today is 800 megawatts. It's owned and operated by SDG&E.

I just wanted to clarify that on page 26 there's a reference to projects that have been discussed in the past, or are currently being discussed. And there is currently no discussion about increasing the Mexico to California interconnection capacity. There was discussion in the 2002 timeframe; a number of applications from merchants that had requested SDG&E to look into expansion of that capability. Those have all been withdrawn. And so at the current time that capacity increase is not under discussion.

I just also wanted to point out that the various interconnection additions that the report points out would be needed in the long-term timing horizon, 6000 megawatts to some 13,000 megawatts, if I recall the report, those not only require construction of facilities across the state boundaries to adjacent states or the Republic of Mexico, but also significant infrastructure additions within the State of California in order to make that energy available to the consumers of the state.

MR. ETO: Thanks, Dave.

PRESIDING MEMBER GEESMAN: Points well taken.

MR. ETO: Other comments? Maybe just in slight bit of defense there, we did this exercise in November and some of these discussions were still active. But I think again this provides a framework. Where would we build those interconnections. Why would we build them. How much might we build. Here we have a basis for saying this is what we might end up needing, and it can provide a framework for thinking about some of those discussions and strategically how we might want to proceed with them.

PRESIDING MEMBER GEESMAN: I would also add that one of the things that we hoped to get into in the 2005 Integrated Energy Policy Report, which both Commissioner Boyd and I are responsible for developing, is a closer integration of our electricity planning between the southern portion of California and the northern portion of Baja. And it's at least possible that that closer integration could result in some of those better interconnection proposals being reactivated. Go ahead.

MR. ETO: Sir.

DR. GALPERIN: My name is Mark Galperin. In your review of the situation I didn't see your evaluation of length, average length of these transmission lines, which tentatively would be over 8 gigawatt total capacity. And I think that as these lines ought to be importing lines, it's lines of over 100 miles length. I would certainly appreciate if you have these numbers to announce. Average length of these lines.

And then if my understanding or expectation is correct, then we should deal again with the problem of long transmission lines. This problem is a tough issue in Brazil. Probably people know that they transmit power from pretty long distance from hydro resources to urban areas for hundreds of miles. And you'll find the same rate of power compensation problems with long-range transmission.

So, this is question number one. If you want me, I say number two, three, or I could wait for your answer first.

MR. ETO: All right. I think one thing that you'll note about the report is there are no dollar signs in it. It's all gigawatts, megawatts. This is a scoping activity. This is a very, you know, this is scenario analysis. This is by no means a cost/benefit analysis. And it's not a policy preference. Really it's an effort to try to bound the kind of resource requirements that our state might need at a given point in the future, based on likely extrapolations of some current trends.

I think obviously going further and justifying specific projects would require you to do the detailed analysis and the tradeoffs, whether it be new corridors, existing corridors, repowering of current units. There's a lot of ways in which this could happen.

But the point is to try to begin thinking about what the resource portfolio might be in 2030. And thinking about, you know, what kinds of actions might we want to take now in order to make that future even a possibility.

I would submit that if we don't take some actions now many of these options will be foreclosed for us, and we will miss incredible opportunities. And that's really the perspective that I was offering.

DR. GALPERIN: But, of course, the amounts of necessary funding, efforts are tremendously depend where those average lines is ten miles or 100 miles. Is ten times more. Five hundred miles. It's proportional to the average length of line you would need to build.

And considering that, if we're talking about long lines, then we should deal with the issue of right-of-way. And this is kind of process including all public hearings and legislators hearings and so forth. And we need to look at some other technologies which would allow us to somehow decrease demand for additional right-of-way, and such technologies are in place.

And I think that it's a good point to bring attention to these technologies and to look at the experience of, again I need to say Brazil, which built another like 7 to 10 gigawatts during several years, and what technology has been used there.

And it's also the number three issue is probably which you address, and this is mostly to the legislators, that it was almost impossible to build new lines here without any investment incentives for transmission line developers. And this is kind of obstacle which shall be overcome nearest future if we wouldn't have a huge problem in very short time from now.

MR. ETO: Okay. I have just two comments. In terms of the types of lengths, you know, in the context of this report we were thinking primarily -- some strategic market hubs. So the lengths are going to be on the order of a couple hundred miles. That's realistically what we're talking about in most of this.

I think the other question that you raise really goes back to this point of why we are trying to do this type of scenario planning, which is to try to seek some consensus about a vision for the future that can flow down into very specific permitting siting/planning processes. And that's why we've chosen a period far beyond what we're currently looking at in this state, and trying to think about that as kind of a template, as a framework under which we could think about the very specific projects. And where all these very difficult issues that you identified would absolutely need to be discussed and traded off.

Other comments?

MR. FLYNN: Yes, Joe. I'm Barry Flynn from Flynn RCI. I first want to compliment you on taking this big step in terms of looking out and just sort of postulating some various futures. I think you do gain some insight.

But a couple things that I wanted to try to add to that. Number one, I would sort of back up what David Korinek said in terms of if you're really talking about transmission and the transmission needs of California, you need to talk about more than just the imports.

And I think in some of the scenarios you develop you would find dramatic differences in terms of the amount of transmission that you need to build within the state. And that's not taking anything away from the focus of this, which is a good thing. But it sort of leads me to ask a question, in terms of just sitting here today, where do you think the most benefit would come in terms of taking the next step forward in terms of the work you have done so far.

It seems like one thing that appears to me is you could try to get closer to the prediction part of this, which you clearly have claimed is not being predicted via the scenarios. That would be one effort in terms of some kind of gross modeling and trying to understand the likelihood of these scenarios.

It seems like the other way is to expand upon them and for each of the scenarios try to lay out on a gross basis how much additional transmission is needed within the State of California looking out 30 years to deliver the power to the load under the gross scenarios that you've developed.

So I'd like to see you comment on that in terms of, you know, your feelings today as to where the next step might be.

The other thing that I think you mentioned in your report or in your presentation is some concepts of right-of-way maximization and land banking, or right-of-way banking. I'd like to bring out any ideas that you have right now. I know it's, you know maybe you haven't done substantial work, but I do see a major problem is this timing issue with regard to transmission being so long in its gestation period, as opposed to other things that can be done much more rapidly.

And I personally think that the way we go about planning transmission needs to be reevaluated from the standpoint of not thinking that today you either decide to build something, and therefore it's a $300 million commitment. But, you know, maybe it's a $2 million commitment in terms of doing some of the earlier parts of the permitting process to make that a viable option and bring the lead time closer to what the other lead times are for other alternatives.

Thank you.

MR. ETO: I really appreciate those comments, and I think that they are well taken. We didn't speak to transmission infrastructure requirements within the state. Again, this was a very gross level analysis about sort of a broad resource portfolio type of management planning exercise.

But clearly the renewable requirement, you know, right off the bat is going to bring up lots of the instate transmission requirements. But again that wasn't the focus. And it's not to denigrate its significance or its importance. Simply wasn't really the focus of what we were trying to do at this gross level of portfolio management.

But in terms of next steps I think your comments are very well taken. And I can tell you what we're doing specific for the Commission, which is to begin trying to apply some of these valuation methodologies that we advocated in the fall to some of the specific projects in California.

I hope the Commission will take you up on some of the areas that you've identified. And that, I guess, is the purpose of this workshop, to provide direction on some of the strategic areas the Commission might explore in this IEPR process.

In particular I think this question of site banking/corridor planning is absolutely an appropriate activity at this time. Whether or not you plan to build transmission, it gives you an -- this is an excellent example of the type of option that the state should be trying to explore now to be in a position at some point to think about transmission. And if you don't take those steps now you're effectively precluding yourself from having that option later on. I think it allows much more of an opportunity to build consensus around corridors, to do the kinds of advance planning that would be appropriate. To just put yourself -- line your ducks up so that it's possible.

And if you don't exercise the option, and it's been a very low cost, I think that's a very worthwhile investment. Because if you do need it and you can't get, then you've lost an incredible opportunity.

And I believe this will be the subject of the next workshop, is that correct, Don? Thank you. Yeah.

Other comments or questions? All right. Thank you for your attention. Let me turn it over to Judy for the next phase.

MS. GRAU: Good morning. My name is Judy Grau with the CEC Staff. We'd like to kick off the roundtable discussion of the development of a long-term vision for the state's transmission system with a brief presentation on some of the drivers that staff believes should be considered in the process we plan to pursue.

Okay, we have five things we want to talk about briefly. A little purpose and background. Commissioner Geesman gave some background. I'll just expound on that a little.

Talk about how we're going to approach this process. An overview of potential drivers that you may want to consider. The roundtable discussion questions, which are also in the agenda. And some next steps.

And so first of all, our purpose this morning, as noted in our workshop notice, is to begin collaborating on the development of a long-term vision for the state's transmission system. By way of background there are several steps that the Energy Commission has taken to bring us to this point, where we believe it's important to expand the focus from responding to short-term needs to planning for long-term needs. And we're going to start with some of the short-term steps.

Beginning in early 2003 the Energy

Commission, the Public Utilities Commission, and the California Power Authority collaborated on the development of a state energy action plan. The plan identified six sets of actions of critical importance that need to be undertaken now. One set involves actions to upgrade and expand the transmission infrastructure and reduce the time before needed facilities are brought online.

One of these actions is for the agencies to collaborate in the integrated energy planning process to determine the statewide need for particular bulk transmission projects. This workshop is a part of that effort.

Another action is for the CPUC to open a rulemaking into changes to its certificate of public convenience and necessity process. You're going to hear more about that from Kerry Hattevik of the CPUC right after lunch.

Another action is for the Energy Commission to work with municipal utilities to help insure completion of expansion projects in their systems for which the collaborative transmission assessment process finds a need.

In August of 2003 staff prepared a white paper on transmission system upgrades, issues and actions. The white paper identified critical system needs, projects of immediate concern, and recommendations for specific short-range actions to be taken during the 2004 IEPR update and future IEPR cycles.

The white paper served as input to the 2003 electricity and natural gas assessment report published in October 2003. It carried forward the major calls for action echoed in the white paper.

Finally, the 2003 electricity and natural gas assessment report served as input to the 2003 Integrated Energy Policy Report, which was adopted in December 2003. The policy report distilled the major themes found in the 2003 white paper and the electricity and natural gas assessment report into two major categories, planning and permitting.

And just for your information all of these documents are available on the Energy Commission's website at www.energy.ca.gov.

While all of these documents describe, to an extent, the value of long-term planning and the importance of incorporating state objectives into planning decision, today's workshop is the first formal event to look beyond the short-term problems and focus on what the transmission grid of the future could look like.

As you've already heard from Joe Eto, we contracted with CERTS to get the ball rolling on addressing long-term transmission planning needs by looking at California's potential needs in the year 2030. The study and the comments we received provide a foundation for the discussion we are about to undertake.

We're going to begin the process of developing a vision today with a roundtable discussion right after my presentation. We look forward to receiving verbal input today, as well as written comments after the workshop. We would like all comments back by April 20th. We plan to post all of the comments received on our IEPR update website.

We will then compile all the comments we receive and develop a draft vision statement for discussion at the next transmission-related 2004 IEPR update workshop which has been set for Monday, May 10th. Staff will then make recommendations to the Committee based on verbal and written comments received at and after today's workshop and the May 10th workshop. These recommendations will be included in staff's draft 2004 transmission white paper which is tentatively scheduled for release in late July.

The staff white paper will then be the subject of a Committee workshop or hearing in early to mid-August and then a Committee draft version will be released in mid-September.

We've grouped the types of drivers into five categories. This list is not intended to be all inclusive, but is intended to provide a starting point for today's discussion.

First, there's a need to consider legislatively mandated programs and their impact on the transmission system. The renewable portfolio standard program, the RPS, is expected to have a significant impact on the location and size of future transmission interconnections. And we heard about that from Joe Eto's presentation.

Another state mandate is the procurement of resources through the CPUC process. At the federal level is the Federal Energy Regulatory Commission's response to the California Independent System Operator's proposed market redesign.

Second is the need to consider state

preferences. As noted in attachment C to the workshop notice, the Legislature made two findings in Senate Bill 2431 of 1988. The first finding they made is that a reliable, efficient and flexible bulk transmission system is vital to the future economic and social well being of California.

The second finding established a preference hierarchy when upgrades are necessary. The first preference is to encourage the use of existing rights-of-way by updating existing facilities where technically and economically feasible. We heard about that from some of the speakers, the importance of looking at existing right-of-way.

The second preference is for construction of new lines in existing rights-of-way where technically and economically feasible.

The third preference is for the creation of new rights-of-way. In all instances the goal is to insure that single purpose lines be avoided by seeking agreement among all interested parties in the efficient use of new capacity.

Another state preference is to improve the environmental performance of the system. The

Energy Commission prepares an environmental performance report on a biennial basis in odd years. The last report prepared in 2003 focused on the environmental performance of the system since deregulation in 1996. The goal was to establish a baseline from which trends in environmental performance can be monitored and assessed.

Strategic goals and opportunities could include such items as planning for low probability but high impact events; taking advantage of technological improvements in transmission; enhancing system security; and making strategic interconnections to other states for both reliability and economic purposes. Achieving a least-cost electricity system could be facilitated by accessing lower cost resources, both intra- and interstate, and by using transmission to reduce the need for and cost of reliability must-run units in local areas.

The workshop notice and agenda contained the following questions: What additional drivers need to be considered in developing a long-term transmission vision. What do you see as the vision for California's transmission system. What steps need to be taken in this 2004 IEPR update. And what steps need to be taken in the 2005 IEPR proceeding.

In addition to these questions we would also like to ask respondents to consider two more questions: How would you prioritize or rank the drivers, especially competing drivers. And how would you incorporate this prioritization into a vision statement.

And so the next steps are we're going to proceed to the roundtable discussion. Again, written comments are due back on April 20th. And we will compile the comments and develop a draft vision statement for our next transmission-related workshop on May 10th.

If you are not already a member of the list server, the website address is given there. If you go to that page and open it, scroll down to on the bottom left of the page you can put in your email address and you will receive all future notices of all 2004 IEPR update work.

Also we have a sign-up sheet in the back and if you would prefer regular mail, you can check that box to also get on the list.

So what we're going to do right now is

take a short break. We need to finish setting up the room for the roundtable discussion. And to that end we're going to place name-tags out around -- we have like 18 -- 18 people who would like to join the roundtable. And so what we're going to do, starting in the order you are on the agenda, the first person is Gary. Gary will be over by the court reporter and you're going to swing your way around and we'll seat you all kind of in that order.

So what we're going to do is take a five-minute break and have everybody back at 10:45. And if people in the roundtable can find your spots, we'll get started. If there's anybody else who would like to join the roundtable please see me and we'll try and get you seated, okay? Thank you.

(Brief recess.)

MR. ETO: Let's get started. So we have a very large roundtable group and I'm delighted to see that. It will be very stimulating of the discussions that we're hoping to have in this next session.

What I'd like to do is re-read the questions that we're hoping that you can all speak to on the first go-round. And then I want to try to outline some groundrules so that we can get through this in an order process.

So the process that I envisioned here will be to give each speaker really just a couple of minutes, one or two minutes. If I see you going on I'm going to start making noises and I don't think I can turn off your microphones from up here, but we really are interested in a very very high level sort of headline responses to the key questions that the Committee is looking for input on.

We'll go all the way around the table one time. I will then ask the Commissioners and their Advisers if they have specific questions for the panel. And then we will open it up for more of a general discussion. So that's the process that we'll follow.

So the questions that we've been asked to speak to in this first session are what are the drivers that need to be considered in developing the state's long-term transmission vision. And what do you see a the vision for California's transmission system.

And then looking more specifically to

what's in front of us, what steps need to be taken in this 2004 IEPR update. And what steps need to be taken in the 2005 IEPR proceeding.

To that Judy added a couple which are: What are your priorities for this process. And how do you see them feeding into these two processes going forward.

So please be very specific in the kind of direction you'd like to offer the Committee and to your fellow colleagues here about the priorities and how they should be implemented going forward.

So I'm just going to go down the list now, starting from the top. We'll ask Gary DeShazo from the California Independent System Operator to speak first.

MR. DeSHAZO: Good morning, and I appreciate the opportunity to be here this morning.

In terms of the questions of the drivers I guess as I see them is that there's issues related to resource procurement; there's issues related to renewables. The ISO, I think, has said a number of times that we have concerns about the load forecasting. While we think that the process that is in place is sufficient, it comes under considerable fire whenever we get to a CPCN process. And I think we've seen that there have been other times when that's been overturned. I think we need to deal with that.

Obviously the generation plans, in listening to the presentation this morning, and talking about the harmony between generation and transmission planning, I guess the first thing that came to mind was the circle of life, which was something that came out of the Lion King movie that there are times when it seems that over, you know, 20 years ago the kind of transmission planning and generation planning and relationship that we had there wasn't all that good. It got worse. It seems to be getting better. But I sometimes wonder if we're not going back to the same place that we were before. But nonetheless, I think that's an important item that needs to be addressed.

The vision for California's transmission system, in my mind, is about subregional planning. I think that this is key, is something that we have to do. California is something, I think, as a state cannot do things on its own. It has to look outward to its neighbors. And its neighbors have very strong ideas about things that they want to do. And so we need to manage that process.

In terms of what needs to be taken or what steps need to be taken this year in your process and next year, the thing that I would say is we need to follow through. The process that you have and the report that's been written I find, while to me it's not necessarily new stuff, but maybe the timing is right that it's good that it come back. Because of the situation that we're in we need to be doing these things.

And so the ISO is very much interested and it's very willing to participate in the process to see that you can follow through with that.

In terms of the priorities, I guess I'd just go back, we've got the deal with the resource part. That needs to be taken care of. We're kind of in a bad spot right now. And without that we really can't deal with transmission infrastructure that goes behind that. Although the ISO, and I believe the PTOs, will do that anyway. But we need to deal with that part.

I think that behind that we would like

to see some work done on the load forecasting part of it. It's a very key item in terms of planning, and certainly within California. And we'd like to see some closure on that.

Thank you.

MR. ETO: And now we'll hear from Kevin Dasso. Thanks, Gary. Next we'll hear from Kevin Dasso, PG&E.

MR. DASSO: Good morning, everyone. I had a handout actually at the outside. It had one slide on it and I was going to use that for guiding my comments. We don't have to have it up there, but in any event, three key things that I wanted to cover in terms of drivers.

The first is a clear energy resource planning and policy goals. That's been touched on a number of times here in terms of the relationship between transmission and resource planning. To the extent that we have those it clarifies the way in which we consider transmission.

The second is predictable market rules and cost recovery regime. We don't necessarily have to have -- doesn't have to be a strictly integrated model or merchant model or whatever, they just need to be predictable and clear. Just thinking about the -- looking at the folks around the table here and others in the room, that if we have those kinds of predictable elements we will figure out ways to address the issue. We just need to know what the rules are.

And then the third point is that -- Gary touched on it, it's been touched on as well, and that is that regional coordination and planning. California may have very clear goals in terms of what it wants to accomplish; however, we are not an island. And to the extent that we're importing resources from other areas, other areas are exporting resources, and there needs to be a handshake and an agreement on that.

In terms of the -- I didn't do this on purpose, but in terms of the ranking and priority, I would put them in this order in terms of the issues that I think drive it.

Our vision for transmission is really that transmission needs to be part of the solution. It's not the solution. It needs to be part of the overall process. And we can't lose sight of all of the elements and focus only on transmission or resources or others.

In terms of what should be considered in the 2004 and 2005 IEPR, I think the Commission has done an excellent job of raising the issues, and I commend the Commission on doing that. I think the debate and the discussion on transmission have advanced dramatically as a result of this Commission raising these issues. So I applaud the Commission for doing that. And recommend that they continue to push the envelope. Continue to raise people's awareness and identify these issues.

And then also, again, including the role of transmission in its scenarios. I mean, again, each of these scenarios that are being talked about, or it's, you know, it's planned, how does transmission play a role and how can it influence the outcome.

So, with that, thank you.

MR. ETO: Thank you, Kevin. Next we'll hear from Patricia Arons from Southern California Edison.

MS. ARONS: Just a word briefly about my name change. I got married in December, so you may remember me as Mayfield.

(Applause.)

MS. ARONS: And I decided to do the old fashioned thing which was not hyphenate my name, but rather just convert over. I've never been at the beginning of the alphabet and it's really quite nice.

(Laughter.)

MS. ARONS: I want to talk for a moment about the vision without getting into the details of the vision. I think that it's going to be very important for the Commission to think about a vision that's driven by principle and not by prescription. I think if it is too prescriptive, ala, we have to build a D-PV2,or we have to do a Tehachapi project, it becomes a very short-lived vision.

Changing conditions, new facts, new perspectives can make a prescriptive vision a very short-lived vision. But one that's driven by principle in terms of the how we're going to do the transmission development, why it's the right thing to do is going to be a very long-lived vision.

With that said, I think you need to focus on meeting long-term needs. As Gary has said, load growth, generation, interconnections, reliability will be major drivers. But we also need to make sure that we are humble in the sense that we reflect that our decisions are societal choices, they're societal preferences. As a power engineer what we say is not necessarily the ultimate in terms of what has to be done, the choice to build and where to build and how and when is often a societal choice. And we need to acknowledge it that way.

We also need to think in terms of the sustainable energy future for California. The Energy Commission has done a lot of work in that regard. And I think we need to go back to those as foundational principles for a vision.

I think we need to do proactive siting in order to deal with the "not in my backyard" philosophy that many people have when it comes to building transmission. And I think we also need to look at technology options that are ways of expanding the existing capability, and be able to deal with growth. A lot of movement out there in the world and in California is a no-growth philosophy, and we all know we can't deal with that. That's just not workable. We have to deal with the growth that's out there. And technology gives us a way of dealing with that perhaps without building new transmission.

We also need to consider what is unique about California. Why is this transmission question different in California than it is in the rest of the nation. Well, one of the things, the history of the Energy Commission has been community outreach and support in dealing with energy questions. We need to, in our thinking, clarify what our roles and responsibilities are for state agencies, local agencies, county agencies. What do we expect of them in terms of their role and responsibility on energy in the future. And then transmission plays a role in that.

What is our view of the environmental stewardship in California. What is our view on how we're going to deal with land use implications of transmission. These are all questions that have to be dealt with as you think about building a vision.

Of course, as Gary mentioned, you have to recognize your market, your regulatory framework. But it's important to think about, I think. Transmission is a foundation for that market. It is not the market. It is the infrastructure over which the market takes place.

And in my view, as a transmission planner, the more robust and flexible a transmission infrastructure you have the more market variations you can deal with without creating congestion problems.

I think getting toward a good robust vision, statewide vision, is going to require us to employ cooperative planning methods. And I think a good definition of rules and responsibilities for the utilities, the ISO, the CEC, the PUC, the various jurisdictions, and even the owners and users of transmission is going to be very important.

Lumpy transmission. You've heard that term. What is lump transmission is an awfully big investment that brings a very large capacity expansion. That is a major undertaking, both in terms of construction and time and everybody that goes into making that happen.

So we need to develop a way of leveraging our existing assets. And that can be upgrade, rebuild, reconductor, but also employ new technology, as I said earlier.

We also need to be mindful, finally, of not building in new vulnerabilities. The reality of a transmission grid and the reality of interconnections with other utilities, with other states, with other regions is that it is a very complex system. It is prone to failure. It will fail in a very big way from time to time. We hope that from time to time is a very long length of time. But it is a reality that we deal with as power engineers.

I think that we should answer the questions of how the grid should be developed and why this makes sense. And I think through that you can then begin to focus on what your vision should be as an enduring vision. It will be a very powerful vision. And it will be one that involves a lot of stakeholders.

MR. ETO: Thank you, Pat. Let's hear from Dave Korinek from San Diego Gas and Electric.

MR. KORINEK: Thank you, good morning, Commissioner Geesman, Commissioner Boyd. My senior vice president, Jim Avery, for electric transmission was very excited about today's workshop and the proceeding in general. And has written a letter to you highlighting many of these issues. And I will present that letter to you later this morning.

I just wanted to quote from the end of his letter. In addressing these issues he points out that in order to protect our state's future the integrated energy policy must resolve these transmission expansion issues to insure excess to the optimum mix of long-range energy resources for California including economic energy imports from outside the state.

This will require licensing and construction of hundreds of miles of new, high-capacity transmission corridors in California over the next 10 to 20 years. To support such expansion it is essential that the state's energy policy include a process to designate appropriately sited utility planning corridors across state-owned lands such as the Anza-Borrego Desert State Park.

We have been looking at a new 500 kV expansion from San Diego to the Imperial Valley which is part of the ISO's vision for a southwest transmission expansion plan. Our studies of possible routes indicate that there are no new corridors available between Imperial Valley and

SDG&E that do not cross either state-owned lands, federal lands, or Indian lands.

And so the concept of a utility planning corridor is especially important. And we would hope this proceeding can incorporate that into the policy, the vision for what the state can do to allocate appropriate space across state-owned lands.

And in that regard I was very encouraged to see in the report the concept of a siting -- or site banking proposal. We're very pleased to see that included. And we believe that the Anza-Borrego Desert State Park needs to be an important component of that site banking effort.

Those are my comments.

MR. ETO: Thank you, Dave. Next we'll hear from Morteza Sabet from Western Area Power Administration.

MR. SABET: Good morning, thank you. As a federal agency we kind of are playing a unique role in this discussion, but nevertheless, I'd like to offer a couple of observations.

Since the early 1992 with the unbundling fragmentation of planning I think we have over-dosed on planning, but we have yet to develop a plan, long-range plan. So on that note I applaud the Commission for taking basically the issue.

In addition, transmission planning, or any kind of planning, for by its nature is a long-term and continuous process. We have had a fragment of process.

In California, you know, there are several electrical islands. I'll be talking about Sacramento later on today. And there are certain facts known very clearly, that local generation is the most effective way of dealing with the demand. But you have a very limited operating area to work with.

And I think the Energy Commission is in a very unique situation to perhaps, having had the privilege of working for the Commission in its early days, perhaps to set a ceiling for which one of the existing sites could be operated for new generation to come in, and to attract developers. And also put the responsibility back where it belongs, on transmission. Because we used to do the stuff that Joe articulated in his opening. The utilities used to do that very good. We used to acquire right-of-way in advance; we used to plan right-of-way in advance and had that continuity. But right now there is no incentive for utilities, kind of echoing the previous speakers, no incentives to do that. You need to incent them.

And also the major element is the relationship with the landowners and the stakeholders at large. The utilities used to have that relationship and cherished it. You cannot do that on a casual basis whenever you need and have a discontinued effort along that line. You need to have a continuous effort and responsibility should be where it belongs.

Thank you.

MR. ETO: Thank you, Morteza. Next we'll hear from Mark Ward from the LADWP.

MR. WARD: Thank you. I know this will probably come as a shock to the ISO, but we agree with the ISO to the extent that transmission doesn't stand on its own. And we're happy to hear that the Commission is looking at a more integrated process as far as generator siting, along with transmission.

In addition to that I think we need to also look at what type of reliability standards we're going to ultimately end up with. And once transmission, if we're going to build transmission, how can we dedicate those facilities to some of the generation projects.

You asked what some of our priorities would be. From a utility perspective I think that we are looking at how can we establish predictable costs on an ongoing basis. How can we preserve our ability to serve the loads that we've said that we're going to serve. And in order to serve those loads can we dedicate our facilities to serving those types of loads.

Not to exclude collaboration in the projects, not to exclude joint projects because all of those things have worked for the utilities in the past.

So, I think that, from there that gives a pretty good idea of what our priorities would be. Thank you.

MR. ETO: Thank you. Next we'll hear from James Feider from the Transmission Agency of Northern California.

MR. FEIDER: Good morning, Commissioners. My name is Jim Feider. I'm here on behalf of the Transmission Agency of Northern California that has 15 municipal utility members.

I'm also a director of the Redding Electric Utility. So I come at this from a perspective of a so-called load-serving entity.

Some of the more important issues that we see in this context of where do we go with transmission policy starts with resource adequacy; the fact that we need to plan 20 to 30 years in the future and not a three- to five-year planning horizon. And when we look towards transmission being part of that portfolio we look for certainty and durability.

We're concerned about the level of dependence that this state has grown to have on natural gas, and we see a strategic issue as what is the future role of natural gas, and what can this Commission do by way of accelerating gas development infrastructure, especially LNG facilities.

We look at the transmission perspective from a regional perspective, as well. We think that the transmission planning in the western United States ought to have a common approach throughout the entire west through the Western Electricity Coordinating Council.

We're concerned about the current market structure that we see where the California ISO is faced with the unenviable task of allocating a scarce resource called transmission. We believe that the ISO going forward with its locational marginal pricing approach is a disincentive to transmission. And we think that the policymakers in this state should take a hard look at putting the brakes on that movement.

We would observe that these themes are common throughout the country today, where states like Wisconsin and in the south are pushing back on regional transmission organizations and this type of pricing scheme for transmission.

We are concerned with the permitting process that we see for the investor-owned utilities. We'd like to see a more streamlined approach so that projects like Path 15 can get built sooner rather than later.

We would like to see an aggressive approach on known problems that exist in various parts of the State of California today.

One of the things that you might want to consider in the next steps of this proceeding is to inventory possible vacant right-of-way. I can recall in a former life where we actually had to cross a vacant right-of-way that PG&E had acquired in the Livermore/Tracy area. And I think a hard look at that, revitalizing that strategy would be worthwhile.

I think that this Commission, through its participation in WECC, as well as other western wide outreach agencies, should talk to your counterparts in other parts of the west to see what might be the best priority and strategic approach.

In terms of the priorities, I've outlined most of them. I would almost put them on an equal basis. The need for resource adequacy to settle where we're at and where we're going. The need to settle on a market design that has certainty and durability. To find where we're going with gas, particularly with LNG facilities in the west, on the west coast. And then lastly, the streamlined permitting process.

Thank you.

MR. ETO: Thank you. Next we have Jane Turnbull and Jane Bergen from the League of Women Voters.

MS. TURNBULL: I'm Jane Turnbull, and very pleased to be here. Once again, we would like to commend the Energy Commission for the work that's being done in terms of integrated policy development. Integrated policy thinking is really the way to go. Transmission is part of the integration of the whole.

One of our concerns, however, is the balkanization of energy in the state. And I raise that today because I'm just coming back from northern California where I participated in a renewables workshop over the weekend in Siskiyou County. And in preparation for that workshop I took a map off the CEC homepage or map page that shows the jurisdiction of the ISO. And that jurisdiction is in yellow; and the part of the state that is not included under the ISO's jurisdiction is in black. And that black jurisdiction is really quite considerable.

The League did have some questions early on in terms of where the ISO fit into things because we really are concerned about good governance and transparency. But it looks as though a lot of the initial problems with regard to the ISO have been alleviated. And the work that has been done by the ISO of late in terms of looking at the existing transmission concerns and planning for the future really seems to be extraordinary.

We also like their approach in terms of looking at how California fits into the overall west. And while we're certainly not taking a position on RTOs one way or another, there certainly does need to be some kind of long-term planning. So we do support regional planning; we support subregional planning; we support integrated planning. And we would like the state to take a better look at the balkanization of the energy organization of the state.

MR. ETO: Thank you, Jane. On the list we have next Andrew Bozeman from the Southeast --

MS. BERGEN: Excuse me, I'd like to say a few words.

MR. ETO: I'm sorry, Jane, excuse me.

MS. BERGEN: I'm the other Jane from the League of Women Voters of California. And I want to reiterate what Jane Turnbull has just said about integrated planning. I'm particularly delighted to hear so many people this morning on the panel talk about the fact that transmission is a vital element in the planning process, but it's not the only element.

And I wanted to extend that to the whole issue of energy, if I will, even though we're in these hallowed halls and the League has worked with the Energy Commission for many many years on many issues having to do with energy. But the fact is that energy planning really has to be seen in a larger, broader context, as well. And long-range comprehensive planning for energy really can't take place without a philosophical, if you will, support for long-range comprehensive planning in other aspects of public policy. Primarily in this case, land use planning.

The State of California does not have a long-range land use plan. And the sentiment, political sentiment has been very leery of going anywhere in that direction. I guess it smacks of socialism or something. But the fact is that you really can't think of the issues of transmission siting without having some concept of where we're going with our land use and our economic development, for that matter.

Commissioner Geesman mentioned before that there was a problem with the statutory requirements that limit the ability to do long-range planning. He mentioned a five-year planning period. Of course, that's ludicrous. So it does seem to me that there needs, the Energy Commission and other involved agencies need to do an extensive public education program and create a contingency among the public for long-range planning. And to have political leaders gain courage to come forth with support for that concept.

And so I think the Commissioners and other leaders in these specific agencies need to bring pressure, if you will, or whatever they can do to get the political leaders to come forth and start talking about the need for us to plan.

Thank you.

MR. ETO: Thank you, Jane. I apologize for skipping over you.

Andrew Bozeman from the Southeast Sector Community Development Corporation.

MR. BOZEMAN: Thank you, Commissioners; my name is Andrew Bozeman. I'm from Southeast Sector in San Francisco. One thing I'd like to throw into the mix that we don't usually encounter when you get a group of engineers together is people.

I know we discuss them as market and

load and as society influences, but people are very important here. And I'm not sure -- I think they're a combination constraint as well as driver. Constrainer in that they do have very much an influence on what we do and where we go in terms of the future. Because as Ms. Arons mentioned, the NIMBY element gets involved there, the "not in my backyard".

The driver, however, I really like the idea of the site banking because I guess visually it hit me as we're playing a tic-tac-toe game here. And if we slow down in our planning and don't get involved in something like site banking, then the population's going to move to a space and we can't go there with our transmission or with our generation, because they're going to resist it.

So, the idea of future planning, because we know where the population's going to go generally. You've got population planners that can see where the trends are going. So to get to jump ahead of them and get things set up so that we can move there when the time comes is, I think, a very wise idea. And it saves us a lot of trouble and money politically, fighting those battles that don't need to really be fought.

I agree with Ms. Bergen that we really need a public education element because the public has got some ideas about this business, this energy business and what it does to them environmentally. That may or may not be true; and so they need some better information. And they need it put to them in a way that not high level, but down to earth where they can understand it.

I cringed a bit when I first heard the let's take the present facilities and expand upon them or increase them, because I'm in the middle of Bay View/Hunter's Point. And we're fighting like hell to try and get two plants closed that have been polluting our community for a long time. Because they're very old; over 50 years old. And they need to be shut down.

So, that bothered me. But when we look at the realities of what needs to be done I think we need to look at technology. What can we do technologically that's going to move us forward. You know, we've got this dependence on gas which is a fossil fuel, but there must be something else we can do because gas is going to run out at some point. And the price on gas is rising now rather rapidly. So that's going to be one of those unpredictable price issues or cost issues that we're going to have to deal with.

So, let's try and get around it. Basically that's it. Thank you.

MR. ETO: Thank you. Next we'll hear from Francisco DaCosta from the Environmental Justice Advocacy.

MR. DaCOSTA: Commissioners, ladies and gentlemen, I'm the Director of Environmental Justice Advocacy. And I applaud all those who put this workshop together to have a vision so that we can address our state's transmission system.

In San Francisco we have some unique circumstances, and in San Francisco we have a number of organizations that allow the constituents to participate. So we've had many meetings with various organizations to address not only transmission system, but also the aging power plants that we have in our area.

And what I see lacking in any discussion in order to address it is empirical data. We can dream and we can create various scenarios, but if we do not have empirical data then we really cannot zero in on any situation.

In San Francisco, even today, we do not have the right information, the current information about our transmission system. We know that we have two aging power plants, and nobody wants to take a decision to close down the power plants.

As director of an environmental organization one of the key factors that we have to address is the ratepayer, and how transmission lines, power plants affect the health of the constituents. And while we may talk about right-of-ways, we need to pay attention as to where we site any of the power plants. Whether it is right that over 90 percent of the power plants are always sited in poor neighborhoods. We need to pay attention to this.

And even as we want to pay attention to the environment, we need to pay attention, as has been alluded to by some of the speakers, about archeological sites. I represent the Muwekma Ohlone and we have many of our transmission lines over shell mounts. And even as we are discussing the Jefferson-Martin transmission line, very interesting concepts come how we can avoid archeological sites and how sometimes people say okay, it's fine to put transmission lines underground near archeological sites, but please don't bring them in our neighborhoods because of the electromagnetic field and so on and so forth.

So we need to respect the native Americans, the first people. And we also need to respect the constituents from the poor neighborhoods equally.

One more point. Even as we plan on putting new generators, combustible turbines, we should not put an emphasis on fossil fuel. And in San Francisco we have an added problem. They want to site -- they're proposing to site three combustible turbines.

And even as they're proposing to site three combustible turbines in this day and age, they want to use secondary effluents, the water coming from sewage treatment plant, to use this in the cooling system. And if there are any scientists here or doctors here, or people who are concerned with their health, in using secondary effluents as a cooling system you release pathogens into the air which can adversely impact the health of the constituents.

So, in the year 2004, 2005, 2006 we need to use the latest technologies, but we also need to pay attention to the health of the constituents, especially poor neighborhoods.

Thank you very much.

MR. ETO: Thank you. First of all, Bill, we're not going to skip over you. I'm just going in the order that we have on this list. So, we'll come back. Sorry.

I do want to follow the process in terms of the list that was developed here, so next we'll go to Bill Myers from The Valley Group.

MR. MYERS: Good morning, and thank you. I hope that you all picked up a copy of Tap Seppa's two-page letter to you all. My objective this morning is just to very very briefly review the highlights.

First of all, let me say that we are in complete agreement with the consultant's report. Also, we believe that our discussions and our investigation should be extended to three additional important drivers related to California's internal transmission network.

Number one, if the peak load grows as projected, the internal power transfers within California will become extremely constrained.

Tap's letter explains how this can be investigated using a concept called normalized transmission capacity. The bottomline simply is that the trade radius of an average generator will be reduced from 234 miles to 146 miles over the course of this horizon we're looking at.

Number two. Regarding the impact of the import of energy, unless the internal transmission network is strengthened, and a number of people have already talked about this, unless it's strengthened substantially benefits of potentially less expensive imported energy will become localized near the border regions of the imported sources.

Third and final, regarding the impact of renewable resources. It is quite likely that the increase of the renewable part of the generation portfolio will require substantial adjustments to the transmission system of California.

In conclusion, our conclusions, our recommendations simply are that such impacts and the methods to mitigate them need to be carefully considered, all of these drivers, before the final recommendations are made regarding resource policies.

Thank you.

MR. ETO: Thank you. Next we'll hear from Rich Ferguson from the Center for Energy Efficiency and Renewable Technologies.

MR. FERGUSON: Thanks, Joe and Commissioners. I won't go so far as to say I approve of everything in the report, because I still don't like using the DOE's projection of vastly expanded domestic gas production. Unless gas goes to $20 a million Btu that's just not going to happen. You might want to revise that, Joe.

Several people have said the main driver of this whole operation is what resources, what energy resources is California going to need and depend on in the future. The transmission is just a way of getting those, you know, from the generators to the users.

And I think on the slide that was put up earlier these were called legislative mandates. But I think Pat said it right. I mean these are societal choices.

And I think, as you see from the report, if you sort of figure out what's happening, I think basically our choices are increased dependence on coal, increase dependence on LNG, or increased dependence on solar and other renewables. And those are the choices. The people understand those. You don't have to educate them too much. Even the people over in the building could probably understand those without too much trouble.

And it seems to me that that's the next thing that the Commission needs to do to build on this report, is to paint the picture of these energy futures that underlie these various scenarios. And try to reach consensus on, you know, where California is going to go.

You're going to have to boil these things down. Not in terms of esoteric transfer capacities and market do-dah and whatever. You really have to boil these down to the very essence of what does it mean, you know, if we become dependent on imported coal from Utah and the southwest; if we become dependent on imported LNG; or, you know, if we decide to develop our own solar and other resources here in the state.

In my mind that's the next thing the Commission has to do, is to paint these scenarios in a way that people can understand, and then take it out on the road show and try to build some consensus for it.

MR. ETO: Thank you, Rich. Next we'll hear from Tom Tanton from Vulcan Power and Silvan Power.

MR. TANTON: Thank you, Joe. And, as an illustration of capacity constraints, I'm also here on behalf of Pacific Southwest Combined Heat and Power Initiative, which wouldn't quite fit.

I'd like to commend Joe and CERTS and the Commission Staff for undertaking this work and the prior work that CERTS has undertaken, which is a result, actually, of some visioning that was done quite a few years back.

I'm going to comment primarily on drivers; some of these may be facets of the existing drivers or new drivers. I guess my most important point is to distinguish between manageable drivers and unmanageable drivers. Some of the drivers that have been identified are manageable through, for example, technology development or policy development.

One of the drivers, I think, is a recognition that emerging is what might be referred to as a smart grid with intelligent agents. A lot better than the old electron pipeline that used to be the design paradigm.

Also associated with the paradigm used previously in design of transmission networks we now have a plethora of generation technologies, some of which might be appropriate at the load centers; others which might not be. I think we need to move away from an exclusively AC driven transmission network design as illustrated by the Pacific DC Intertie. Local storage will become more cost effective.

I'm glad to see the low load forecast part of the scenario, Joe. I think there may be a flip side to that with a high load from some sort of phantom use. Perhaps electricity used to produce hydrogen for transportation applications.

Don't over-homogenize the various resources. I see in your scenarios you talk about a high penetration scenario for renewables. Renewables are very diverse in terms of their performance and impacts on the transmission grid and operation thereof.

And I think perhaps the most important aspect or driver has been alluded to from a couple of prior commenters, and that's the interconnected dependencies of our various infrastructures, be it water, telecommunications, banking, transportation, et cetera. Electricity is a supporter of and is supported by each of those other infrastructures. And until we see what the future vision of those other infrastructures are, we really are working somewhat in isolation.

That's -- I'm done.

MR. ETO: Thanks, Tom. Next we have Perry Cole from Trans-Elect.

MR. COLE: Thank you. Appreciate the opportunity to be here and, like many others, commend the Commission for taking on this activity and having this discussion.

For those who don't know who Trans-Elect is, and our subsidiary, New Transmission Development, we are an independent transmission company. That's our only business, is high voltage electric transmission. We own a system in Michigan, Consumers Energy. And we're the managing partner of AltaLink in Canada.

We are also in the Path 15 project. We raised over $200 million in the construction of Path 15, along with partnering with Western Area Power and PG&E. PG&E is doing the substations. I was out on the site last week and everything is going very well. We've got single steel poles up, as well as lattice towers are now constructed. And we're starting to string wires,so we expect that to be in service by the end of the year.

We also are out looking at many other new transmission projects around the country. One we've announced is working with the Navajo Nation. We are looking at building a 500 kV line from the Four Corners Area to Las Vegas. And are looking, you know, to serve Arizona and California with new resources, and working with the Navajo Nation to increase their economic development activity for the benefit of their people.

A couple of comments that we would have. One thing I should say is we are a regulated transmission company. We're not a merchant transmission, so we are regulated. And so we are very interested in continuing to expand our business as a regulated entity. We do not believe that the merchant transmission structure is going to work very well, if at all. So we are focusing on regulated transmission activities.

Some of the drivers to be considered, and I think this has been mentioned by others.

But there is a lot of activity going on outside of the state in terms of transmission planning. And certainly California should be very aware of what others are thinking about in terms of regional transmission planning within the WECC. And I know that the Cal-ISO has been very active in that activity, as have several of the other major utilities, one being the STEPP group, as well as there's another group in the Northwest called the Northwest Transmission Planning Group. There's a Rocky Mountain Area Transmission Planning Group. And SWAT, which is an Arizona/New Mexico Transmission Planning Group.

All those utilities and various state agencies are involved in doing regional transmission to try and figure out what is the best solution for transmission, both within their respective states, but also within a regional perspective.

And while California is such a dominant entity in the west, many of them are factoring in California's load growth into their various scenarios. And it's a big major factor for a lot of the states, particularly the Rocky Mountain states who are looking to try and export. And they're looking at economic development activity similar to the Navajo Nation, as a way to grow economic power plants and transmission lines. They actually are looking to want to do that to try and serve and build the tax and job base within their respective communities to try and serve the high growth areas which are primarily the southwest and California.

So, I don't -- that is not to say that there isn't a lot of transmission that needs to be done within the State of California. I certainly totally agree with that. And we are very aware of that and are interested in participating in those type activities.

Another point would be to try and focus on maybe -- a lot of the regional planning groups are focusing on like 2013 as a timeframe. I get a little concerned when I hear, you know, 25, 30 years. I can see that in terms of cost recovery, but it's very difficult to implement something that maybe is needed 25, 30 years from now. There's so many variables that can change that I think really a five to ten year, maybe ten years, which is what a lot of the subgroups are looking at, is something that should be considered.

I say that, if you think about the impact that China has on various commodities and prices of commodities around the world, as an example. If we try and plan 25 years out we may have a tough time doing that. Although, with that said, I think this idea of site banking makes a tremendous amount of sense, that was mentioned earlier.

So, with that, I'll --

MR. ETO: Thank you. Next we have Bulant Bilir from Solargenix.

MR. BILIR: Thank you, good morning. I appreciate this opportunity to talk about transmission systems. First of all I would like to say something about the technical work. We have talked about all these issues and I was wondering whether we'll do some, you know, parallel technical work. Because in technical work we can talk something in the scenarios; also some, you know, technical scenarios. Some issues come into existence and they may not work what we talk about, you know, our general scenarios.

So the major issue here, as far as I know from my experience, the data, real data. So, for example, there are systems and so for some islands they have data. And other island they have data. But they are interconnected then the whole data is needed.

I think that for the transmission study all these data are really important and we are supposed to find a way to process all the data to better the use of the transmission system. This is one point.

So, as a separate utility I was wondering whether that utility has the whole data from the system or just part of the data.

MR. ETO: Well, this session really we want to focus on priorities for the IEPR process, in terms of what you see as the key drivers for developing a long-run vision on the priorities in this update. If your recommendation is to --

MR. BILIR: For example, my point is for the renewable resources, for in deregulated then why we have renewable resources. So, in order to, you know, utilize these renewable resources we need to connect up to the power grid.

So do we need the whole study for that renewable systems, and maybe in the long run we can put something. We need to get some studies, maybe direct by the renewable resource companies like Solargenix.

For example, Solargenix is trying to, you know, transfer power from the Kramer substation ten miles northeast of the Kramer substation in the desert area, to the Los Angeles area and the San Diego. So they need tie lines and also some studies are needed.

MR. ETO: Okay. Thank you.

MR. BILIR: And actually I'd like to mention all these. So, thank you.

MR. ETO: All right, thank you. Next we'll hear from Barry Flynn from Flynn RCI.

MR. FLYNN: Thanks, again for this opportunity to talk to the audience and the Committee of the Commission.

I want to focus my two minutes on the need to study the impact of additional transmission into load pockets in California. Specifically San Diego and Greater Bay Area, and how RMR costs can be an important driver for this transmission.

I'll concentrate more on the Bay Area because I'm more familiar with the issues there and probably less likely to get into trouble. I spent ten years as a transmission planner for

PG&E, ten years as Director of Utility for the City of Santa Clara, and been a consultant to the Cities of San Francisco, Santa Clara, Palo Alto and Alameda on transmission issues for many years.

Let me make clear that I have strong support for the work completed by the staff in their 2003 Integrated Energy Policy Report and the starting of the 2004 update. More work needs to be done to analyze the difficult-to-identify benefits of transmission delineated in that report. I'm really anxious to know how you do it.

But I want to focus on the immediate need for the CEC to contribute to the efforts to identify RMR reduction benefits and load pockets like the Greater Bay Area as an important driver of new transmission.

In its 2002-2012 electricity outlook report the CEC indicated, and I quote, "the risks of power supply shortages for 2003 vary for different parts of the state, from little or no risk for northern and central California, and the largest municipal utilities, LADWP and SMUD, to a low risk, about 1 percent, for southern California, to a noticeable level of risk, about 14 percent, for San Francisco."

I believe that electric service reliability in load pockets can be increased, and dollars saved at the same time, without accounting for the more difficult-to-assess benefits of transmission like reduction in market power, savings in natural gas, reduction in pollution or reducing customer outage costs. Let's concentrate on the low-hanging fruit as we develop more sophisticated tools.

PG&E's estimated annual payment in one of their filings, the 2002 filing with FERC, for RMR was $297 million a year. Approximately 4000 of the 7400 megawatts of RMR needs is in the Greater Bay Area. If the average cost happens to be the same, and I'm not saying it is, then the annual payment for RMR in the Greater Bay Area is about $160 million. That would justify a transmission investment of about 1 billion.

Since the savings impact will be locational specific within the Greater Bay Area, I believe a lot of transmission can be justified on this savings alone. Conversely, I'm sure some portion of the current RMR capacity is the most economical way to provide local reliability services. We owe it to transmission ratepayers to replace the critical reliability services now provided by RMR contracts when it is economical to do so. And to know that we have to do some more study work.

I'll be happy to share my vision on how the CEC can build upon the efforts that are now being put on by PG&E and the ISO to study this problem if opportunity arises this afternoon.

Thank you.

MR. ETO: Thank you. The last person I have on the list is Hal Romanowitz from Oak Creek Energy.

MR. ROMANOWITZ: Thank you, and I appreciate the opportunity to give you some thoughts today on the process, which we're glad to see it moving forward.

I think that it's important, as the CEC works on the transmission planning, that it create a process that is action-oriented and accommodates obvious urgent needs as it integrates its activities with longer range priorities and planning of newer and fully integrated facilities.

It's important that you remember that this is a human process. And while we think we can lay out what is obviously the best situation now, we will be wrong. We can do well, but it'll iterate over time, and we should not delay any further in solving obvious important needs.

There are projects now that are well planned, environmentally evaluated and have a high probability of an integrated fit with whatever the overall final transmission system is going to be. And we should not wait for the planning process to move a long way forward to get some of these high priority projects to move now.

There's obviously been -- there's significant impact that is obvious over many years that has resulted from the changing in the transmission process. And certain important areas are just woefully under-served. And a failure to move now and quickly will absolutely prevent the full competitive optimum achievement of the RPS program. So that there will be a significant cost associated with delay.

It is important that the transmission planning process integrate all of the existing islands within California. There are significant transmission resources that each one serving its own little purpose could, when integrated, create much greater value for the state.

And there are at least five separate islands that come to mind. The three of the original IOUs, the transmission facilities of the munis, and there are some private transmission facilities, all of which could be effectively integrated to give California greater economic value.

As we go forward and plan the use of the facilities, it is extremely important that existing and future facilities be fully utilized. Today there is a woeful under-utilization of existing facilities, and we will create new facilities at an environmental impact and economic cost when by better techniques we could better utilize some of the existing facilities.

Transparency is absolutely required if we are going to get a full wide exposure to how much a facility is currently under-utilized and can be better utilized. We need to create processes that will make clearly available the histograms of each of the transmission facilities that are in existence, and that are planned, and provide the tools to effectively integrate and use that unused capacity.

We need to facilitate the use of facts

devices and energy storage so that these lower cost, low impact devices can be effectively integrated as they become increasingly economic and have increased economic impact as they obviously will in the, really the near-term planning horizon.

So that we really need to reverse the process that has occurred since 9/11, and find a way to facilitate a greater transparency rather than a decreased transparency, and make these processes open, information open, so that the industry can effectively utilize the resources and the impacts that do exist.

Thank you.

MR. ETO: Thank you. Thank you, all, panelists, for being succinct. I know that we're very close to the time that we'd allotted for this. I would like to open it up for public discussion, additional comments from the panel. But before I do that I'd like to ask the Commissioners or their Advisers if they have any specific questions they'd like to put to any one of the panelists for further clarification before we do that.

PRESIDING MEMBER GEESMAN: I had one for

Tom Tanton -- Tom, I didn't quite understand what you were talking about when you said that we needed to look at the development of other infrastructures which have a tendency to drive electricity infrastructure. What other infrastructures were you thinking of?

MR. TANTON: Well, actually a number of them, and they're critical. One is the natural gas system, which, to a large degree, is both managed and moved using electricity, which then in turn uses the natural gas that's delivered.

Telecommunications, banking from the standpoint that there are likely to be a lot of trades that will be clearing on a very rapid basis. The banks rely on data warehouses. And those data warehouses require reliable electricity.

The transportation system is similarly dependent on electricity and the internet and everything else. If you've ever been in the San Francisco Airport and there's a minor power glitch, the internet goes down. Nobody knows where the planes are, nobody knows where the passengers are, everything stops for two or three days.

It's that interdependency of critical infrastructures that I think will drive the future of transmission capabilities and needs.

MR. ETO: Any other questions, Commissioner Boyd or --

COMMISSIONER BOYD: I don't have a question. I just have some maybe quick observation. I was grateful for the many references to resource planning, which I chose to interpret as kind of overall systems planning and systems integration, a favorite theme of mine.

And it's been talked about not just in this area we're discussing today, i.e., transmission and its interrelationship with generation and new technologies that might be available to meet our needs, but as it relates to all three legs, as I like to say, of the energy stool.

Land use planning, another favorite subject of mine. I don't know if our society is capable of dealing with this. I've been waiting a lifetime and it is a real issue. And the trouble is when we first got concerned about it there were maybe 16 to 20 million of us, and now there's 34 to 35. And so the site banking concept that many of you have embraced may be a last great chance to get ahead of the curve.

With respect to -- I shouldn't venture into environmental justice, but I will, the gentleman's comment about planning new power plants in disadvantaged communities and what-have-you.

I think this Commission is very sensitive to that, but I like to loop it back to land use planning. Had we a better way to finance government in the first place, we probably wouldn't have had developments build up to the fenceline of every what was once remote facility or plant or what-have-you. So that is a dilemma that, to me, ties back to land use planning.

Natural gas dependence and then the discourse, the conversation took place between the various infrastructures keenly important. And how to deal with the planning horizon. I mean the comments about the need for long term, but the short-term nature of things. And the ever accelerating pace of everything makes it very difficult to deal with.

But this is the issue we're trying to grope with. And I think you've all dragged the iceberg out of the water and up on the table. And, you know, now we see a bigger piece of the whole thing. And we need to deal with it.

And so I'm pleased with what I've heard. But a lot of issues to dissect and deal with. And we've got to, or else. So, thank you.

MR. ETO: Okay. Commissioners, let me ask you if you would be prepared to see if there would be additional comment from the public speaking to these drivers.

So, let me ask now if there are those in the audience who didn't sign up to be part of the panel who would like to speak to this question of the drivers that should be considered in developing a long-range resource plan -- transmission vision, excuse me, and specific actions to be taken in the IEPR, both this year and next year?

This gentleman.

MR. HAMMOND: I'm Richard Hammond with Optimal Technologies. I want to encourage the group working on the drivers to very explicitly call out efficiency of the transmission grid going forward.

There's discussion of a number of things that will be served by making the grid more efficient.

Well, what does this mean? We've spent a lot of time as a society doing energy planning the last 30 years, talking about more efficient end use, talking about more efficient generation. But we have not focused on the theme of making the transmission and distribution grids more efficient.

It's possible to do that with increased applications of hardware, with increased improvements in software ability to develop better databases, closer to real time and so on.

It's very important, I think, that this community of energy planners, in doing this very important process of transmission planning, elevate specifically efficiency of the transmission grid to a level of driver status.

Increased transmission efficiency will decrease congestion, will decrease losses in the grid, will allow a more transparent base to address Mr. Romanowitz' theme, will help to integrate transmission and distribution systems.

This Commission is doing some very important R&D work on the way in which distributed generation is creating new complexities in the distribution system, and the relationships between distribution system performance and improved performance in the transmission grid.

And Ms. Arons' comment about infrastructure, the transmission system providing infrastructure, that, itself, will be not only the basis for a variety of improvements in planning capability, but if we are going in any degree at all to a market-based system, you cannot have an efficient market if you don't have an efficient infrastructure on which it's built.

I think I've covered my points. Thank you very much. Thank you, Commissioners.

MR. ETO: Thank you, Richard. Any other comments from the audience speaking to this issue of policy drivers and/or priorities?

Seeing none, let me turn it back over to the Commissioner.

PRESIDING MEMBER GEESMAN: I think, if I'm not mistaken, this is the time we had scheduled for a lunch break.

I want to thank all of you for participating in this, and also our staff for lining up such an impressive and diverse group of people.

I think this has been very helpful and I look forward to this afternoon, as well.

(Whereupon, at 12:02 p.m., the workshop was adjourned, to reconvene at 1:17 p.m., this same day.)

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AFTERNOON SESSION

1:17 p.m.

PRESIDING MEMBER GEESMAN: We want to lead off the afternoon with a brief presentation by Kelly Hattevik from the California Public Utilities Commission, to describe the process they're going through right now. Kelly.

MS. HATTEVIK: Hi. My name is Kerry Hattevik; I work for the Public Utilities Commission in the division of strategic planning. I've been doing a lot of work on transmission over the past year. As a fallout of the energy action plan which said that the Commission would be looking at its transmission planning process and evaluating how to sort of update it and improve it, I sort of embarked on looking at both the federal and the state side on overall transmission planning and what the problems are, what the current process, and make some recommendations for improving those.

So let me start out by talking about what the Commission is doing on transmission, and then I'll launch into some of our major efforts.

The PUC has several active transmission planning proceedings to address transmission issues. The first is our transmission OII. Our transmission OII is doing two major projects at the moment.

One is developing an economic methodology with the ISO. That is to more fully capture the economics of transmission projects. Since the markets have been active the dynamics and the pricing associated with various transmission problems have been harder to capture. So, through the various transmission proposals the Commission has recognized that we need a more dynamic model to capture the economics of transmission projects.

So the ISO and the utilities and the Commission, the PUC, are working together to develop that model. I'll talk more about that in a few minutes.

The other proceeding in the transmission OII, the 970 proceeding as it's also called, is the Tehachapi. The Tehachapi is a review of the wind transmission in the Tehachapi area, and the transmission associated with that. Currently there's a proposed decision floating around; I think it's open for comment. And I think the proposed decision is expected in a few months --

I'm sorry, the final decision is expected in a few months.

There's some sort of thorny issues associated with the Tehachapis, and that's that, you know, unlike where you do some of the regular analysis on whether a project is needed, or the economics are -- how the economics are on transmission, with renewables it's a little bit of a different analysis. Because you can't pick the site of them. They are where they are, and then you just need to find the best transmission configuration to accommodate that. So it's sort of looking at transmission from a different perspective in this Tehachapi proposed decision.

Number two is our transmission streamlining OIR. This is a fallout of the report that I wrote addressing where we think the major problems are in the existing transmission planning process. And this OIR was -- that report was used as a foundation for making changes to our transmission planning process at the PUC, as well as working more closely with the ISO to streamline some of these transmission projects. I'll talk more in depth about that in a few minutes. But that was a process that's already underway and where it's sort of on a fast track for decision.

Three is we have three major CPCNs where we determine need for transmission projects and permit it. The first is Jefferson-Martin; that's a transmission line on the Peninsula. That has had its final energy impact report done, and the ALJ is developing a decision as we speak.

The Miguel-Mission line. That is going through public participation hearings. There's a decision anticipated before the Commission in June. And then the Tehachapi, which I also just spoke to.

In the report that I did earlier this year, looking -- that sort of came out of the energy action plan, sort of identified five key areas where there's problems with existing transmission planning process.

They're sort of self-explanatory as we go down here, but I wanted to discuss where the Commission's actually attempting to address each one of these problems.

We recognize that the transmission planning process needs to be better. It also needs to be more comprehensive and integrated with the federal side. We're taking actions in each of these areas.

The first is lack of a comprehensive planning. Since we sort of -- the utilities became deregulated, the transmission planning process didn't keep up with the change of the dynamics in the market, those that were investing, where the generation was going to show up and so forth. So transmission planning has been a challenge, to say the least.

Partially because generation is built so much faster than transmission. And also partially because we didn't know where the generation was going to show up. And a lot of it isn't even showing up in California. But it still creates transmission need in California. So a lack of a comprehensive approach is really probably one of the key problems.

What we're proposing to do is to try to integrate transmission planning into the procurement and the demand side, so the demand response energy efficiency and actual generation procurement. Integrate transmission into that so you have a comprehensive planning where transmission is there when you need it. Not really as it is now, I think, chasing generation.

So the generation shows up, we have transmission need. And then you're already behind by the time you make that realization. We're trying to address that in our procurement proceeding where the utilities do sort of their coordinated planning where they say here's our need out five, ten, 20 years. And then they put the package together on how they're going to meet it, both on the demand side, both through energy efficiency and other means, in addition to supply and transmission.

Balkanization of the existing process. The process is balkanized. I think somebody earlier here was talking about RMR. I think RMR is a great example of balkanization of the process. While I'm an absolute believer that we need it and we have needed it, until now I don't think it's an efficient, effective or a way to, on a long-term basis, address transmission.

RMR for, I'm sure everybody in this room knows, but it's essentially they're costs that go through the transmission rates to address a transmission constraint or address a local need. So they are generators that have to be on to support the transmission system.

In our long-term procurement plans we've asked the utilities to address these local needs in their long-term plans. Either address it through demand response energy efficiency, local generation or transmission. But in the long term, mitigate the need for these annual RMR contracts.

The annual nature of the RMR contracts also is a -- it also, you know, flies in the face of long-term, comprehensive coordinated planning. And the other problem with them is they're very expensive. I think someone was talking about the PG&E costs. The total costs for last year were $360 million.

So I think you could justify much more efficient and cost effective ways of meeting that need through looking at the long term.

Again, the utilities and their long-term plans are supposed to address these local needs, in a way to address those problems in the long term.

Redundancies in the existing process between the ISO and the PUC. This was the -- in developing the report and making recommendations this was what I heard most of, was what are the biggest problems. And that's that the ISO does a very thorough, comprehensive region-wide and local planning for transmission, working with the utilities, munis and regional entities.

They determine need. Sometimes that's for very small projects; sometimes it takes a long time. And it's, you know, of the nature of Devers-Palo Verde 2. It can be all sorts of things, but they do comprehensive, they do environmental, they do public participation; they look at options; they run power flow. They do a lot of things. The utilities and the ISO, together, put a lot of work in developing what that project is before it's brought to the Commission for permitting.

And the biggest complaint is that essentially once it's brought to the Commission for permitting we redo all that. We start environmental needs; we start looking at alternatives; we start it all over again.

So what I heard from a lot of people and looking at some of the existing problems was that the Commission should recognize or participate in, and then recognize, what efforts have gone before in that project selection.

In recognition of that we have initiated the transmission streamlining OIR where we are proposing to use the ISO's determination of need, and not revisiting the question of need. It's to directly get at this issue of redundancies in the process that potentially hang it up.

Like I said, I'll talk a little bit more about the details of the transmission streamlining OIR in a few more minutes.

The lack of a dynamic method to assess project economics. I talked a little bit about that. That's being dealt with with the ISO's economic methodology. That is going to be integrated into our 970 decision and adopted by us eventually, with full participation from the public. And input from entities such as the CEC and the utilities and others.

The fifth one is sort of an issue sort of close to my heart, because I sort of sit on the middle between the federal and state side at the Commission. That's why I was able to, I think, see where we're not doing as good a job as we could have in integrating the federal and state policies.

This is really a critical issue. On the state side we do a lot of work that impacts transmission planning. We do transmission permitting; the CEC does transmission siting; the PUC's doing resource adequacy; and the utilities are contracting for this generation.

On the federal side they're doing market design; huge impacts for transmission. The federal side does transmission pricing. The federal side does interconnection rules; the allocation for the new cost of that transmission. In my view those things need to work absolutely seamlessly to get efficient results. And they haven't been in the past. I think we're doing a better job.

Examples of that are, for example, deliverability requirements. I think we've recognized that we need better deliverability requirements. You know, the ISO has recognized that in their large interconnection rule before FERC. They've proposed deliverability requirements. They've also proposed them at the PUC's procurement proceeding to guide utilities in going out and procuring their generation. So that when they procure their generation it's got the transmission to go with it.

So I think we're trying to sort of

bridge the federal and state side on the deliverability requirements. Same thing with the capacity rules. And a lot of the rules associated with interconnection. What are the rules associated with the transmission associated with interconnection and who pays for that. We're really trying to address that on both the federal and state side, as well as transmission siting.

So, there's a lot of places we're active both on the state side and looking at trying to integrate transmission needs into the overall energy efficiency demand response procurement side. As well as on the federal side to make sure that those things line up in a way that the right price signals are there. You're not putting perverse incentives out there in other ways.

The other area I would say that there's a big state/federal dynamic is in the market design. Whether ISO's proposal for a revised market design. A lot of the pricing rules, as they stand, provide some pretty bizarre incentives for location of generation and the costs associated on the transmission side. We're trying to bridge those as we're going forward in MDO2 to make sure that there are better pricing incentives out there to do what makes sort of least cost/best result on the generation/ transmission tradeoffs.

The transmission OII and development of economic methodology. The ISO is currently doing workshops in the development of those, the economic methodology. The hardest thing about developing this economic methodology and what is really needed is a means to model market prices. Kind of a big challenge.

The other big one is the way to do the dynamics associated -- economic dynamics associated with market power. That's probably the biggest hill the ISO and all the participants in that workshop process have; it's the hill they have to climb. But that's what's probably going to make this better than what we have.

So, I think that's probably going to be an ever-changing, you know, ever changing as we learn more and we're able to put new inputs into that as we develop it. The ISO's planning to present that economic methodology to the Commission in June. The judge anticipates a decision on the economic methodology by the end of 2004. We anticipate a full, open process, and you know, critique, and trying to make it better all along the way.

But we recognize whether it's us that does transmission permitting, or anybody else, they need this model. And the ISO needs it. And I think that the ISO, having the same model that the utilities use when they assess the economics, you have one model over, you know, across the board. And that the PUC accepts it and other participants in the market accept it. You're going to get some better results in the utilities, and other PTOs around the state will know what, you know, what the standard is when they're proposing a transmission project.

So I think just having it well known, what the parameters are and it will facilitate transmission siting. And hopefully make the demonstration of the economics a lot easier. And we'll not have those hurdles that we've had in the past in that regard.

The transmission streamlining OIR is basically based on this economic methodology. We want to integrate transmission planning into the utilities' overall procurement plan. We want -- and then the way we're structuring is that overall procurement plan, the utility will propose their overall 10-, 15-, 20-year outlook and say, this is the transmission component. This is what we're going to do on demand responses, what we're going to do on energy efficiency, this is what we're going to do on generation. Here's our plan.

That will both reflect and will reflect in the ISO's comprehensive transmission planning process. We're anticipating the ISO will be the one that does the details; run the power flow analysis; determine what's needed, both on a regionwide and state, you know, Cal-ISO grid-wide basis.

They're going to do the details. We're going to do the high level transmission integration portion of it. Once the ISO has determined that the project's needed, the utilities will bring it to the Commission. We will not revisit the question of need. But we will conduct CEQA and have a public process. But we're going to really give it to the ISO, who we consider sort of the transmission experts in the state, to tell us whether the project is needed.

And deliverability is integrated to that, but it's also separate in the sense that we are developing individual deliverability rules through the Commission's procurement proceeding. So that when the utilities go out and sign up capacity, there's a deliverability criteria that the ISO signed off on and others have signed off on, so when they sign up that capacity it's already integrated into the transmission side.

The transmission streamlining OIR. Recognizes the efficiencies and redundancies in the existing process. To sort of eliminate this overlap between the ISO and PUC efforts we proposed changes to our general order 131D, which will say to the extent the ISO determine need for an economic or reliability project, we're not going to revisit that determination of need.

For the economic methodology we would like the ISO to use this established economic methodology that we've agreed works. Once they've applied it, we're not going to revisit the question of need. And we're hoping to have that final decision on this revised process in the fall of 2004.

I believe comments were due tomorrow on that ISO's initial comments on this. So, it's already underway and it's in play.

And that's it for me.

PRESIDING MEMBER GEESMAN: Thanks very much, Kerry. I appreciate your being here today.

Why don't we move on then to the presentations we've got scheduled for this afternoon, and shift the focus more to the immediate problems facing the state's transmission system, potential, immediate, short-term solutions; the impact on renewable development; and the consequences of permitting uncertainty.

First up is Gary DeShazo from the ISO.

Judy, should we have everybody come up simultaneously to just sit around the table, as we had before?

MS. GRAU: Yeah, if everyone would like to; we've left out the name cards in order.

PRESIDING MEMBER GEESMAN: That might be more convenient.

(Pause.)

MR. DeSHAZO: Well, thank you, again, Mr. Chairman, Commissioners, for the opportunity to be able to come and speak to you again. I was here the first time, and it was a great experience. I think a lot of work has been done since then, a lot of very good, positive work has been done since then. And the ISO is looking forward to the remainder of the work and actively participating in that.

What I plan to do today is, I know that there's an interest in talking about the short-term transmission projects. I, because we have a number of the other, the PTOs, here, and other folks, I'm going to let them talk about the specifics. And so I'm going to try to keep mine a little more on the general side with regard to transmission planning.

And I would also just maybe call your attention to the picture that I have here, and I think some more are going to show up later from Morteza, but the poll is that for the Path 15 project. And that is something that has caused quite a bit of excitement over, I think, the last couple of years. At least at this point it's good to see something that's going up, and a transmission project that I think all seem to believe is the right thing to do, is actually being constructed.

So let's talk a little bit about where the problem areas are. What I've done is take the State of California and highlight its key areas. And one of the first things that I really want to mention is I say problem transmission areas, and I think I just pulled that off of the sheet. And really that's probably not the right thing to say. I don't know that they're necessarily problem areas; that has, maybe, a bad connotation, given the work that's going on. I need to say that at least for my involvement with the PTOs that are involved in the expansion plan process, that these folks are doing a fantastic job in looking at their ten-year expansion plans in their systems.

And so to say something like a problem area is really maybe misrepresented. I think maybe a better way to say that or to put it would be an area that we really need to focus on.

But, what I have shown here is four basic areas. We can start down in the south, San Diego. I think that everyone is pretty much aware that there are load-serving capability issues there. There are a number of things that San Diego and other stakeholders are involved with that are trying to address those.

There's a small circle around the Devers area, which is more related to transfer capability, and ultimately load-serving capability, also. Edison and others are involved with doing some stuff there.

Some of these things are related to the STEPP effort, which is the Southwest Transmission Expansion Planning Process. I suspect that it's possible that some of the other PTOs will possibly talk a little bit about that, and some of the stuff that's happening there.

In the Tehachapi area, obviously that's the key for renewables, some of the -- or the efforts that are going on there. The ISO actually has approached this as an opportunity to look at ways to integrate PG&E -- a portion of PG&E's system with Southern California Edison's system.

Quite frankly, the bottomline -- well, it doesn't provide all the transmission capacity that would be proposed for what Tehachapi is, but it's an opportunity to possibly tie the two systems together to bring some benefits in terms of integration. Now, that is something we'd like to see at least discussed further. And whether or not that pans out remains to be seen. But at least we saw that as an opportunity.

PRESIDING MEMBER GEESMAN: Would that also facilitate greater imports from the southwest into the PG&E system?

MR. DeSHAZO: I don't think that it would do that. I think that there's some opportunities, I mean there's always a possibility. It has not been looked at that way before. It's something that we could certainly probably look at, but I think mostly it's the opportunity to integrate some of the systems in that area.

It's not a very strong system, as it is. Which is, when you talk about Tehachapi there's a lot of stuff that really has to be done to make all that work. Certainly if you're talking about the number of megawatts that have been talked about.

But I think in terms of an opportunity to possibly stage some things that there might be the ability to move megawatts back and forth.

I work mostly with PG&E, the Fresno area is there. We're always looking for ways to try to improve the load-serving capability for that area. Although the expansion plans that we have in place are addressing that, but this is something that we felt would be worthwhile to look at.

Last, but not least, is the Greater Bay Area. Of course, the oval there is much larger than the others. Obviously it's a much larger area. It encompasses the City of San Francisco and the Peninsula, all the way down through Moss Landing, San Jose, all the way across through the Delta.

PG&E has a tremendous amount of transmission system in that area. Of course, the Jefferson-Martin project is part of that. But there's also a lot of generation that's there. And a lot of new generation is being proposed. And there's also the opportunity for existing generation to be retired.

And I think that looking at it from a voltage stability perspective, a load-serving capability perspective it's something that does require attention. And I also think that there's some opportunities that we would want to take a look at for integrating some more 500 kV infrastructure into that area as it grows out into the longer term.

And obviously we're talking about out to 25 or 30 years, certainly within that timeframe. But, I'm really thinking something more in the 10 to 15 year timeframe. So, it's something that requires a lot of attention and things that we're working on.

Given the areas that I've talked about, I thought that it might be appropriate to provide an idea to everyone, some of the projects, and what actually has been occurring since the ISO was first started up.

For 2003 the ISO has, or will be, approving approximately 21 projects that have been proposed by the PTO. That represents approximately $700 million in capital investment. Now, you need to understand that that also includes the Jefferson-Martin project that's slightly in excess of $200 million. So there's a good portion of that there.

But there's a lot of transmission infrastructure that's being planned by the PTOs, that's being proposed to be installed. Since the startup in 1998 we've had about 271 projects approved, and a total capital investment of approximately $2.3 billion.

The main reason that I wanted to put this up here is to illustrate that there is a lot of work that's being done. There's a lot of effort being placed in making sure that the infrastructure is sufficient to meet the reliability needs of the area. There's a significant amount of money that's being spent in order to make sure that all this stuff works.

Now, I want to talk a little bit about the grid planning process. This is something that you've probably seen in other forums. What I have on the left-hand side are some process purposes. These are some of the things that we use as sort of our objectives in terms of grid planning. Obviously it's interconnecting generation; the reliability aspects; insuring efficient use of the grid; operations; congestion issues and ratepayer benefit.

In 1998 we had a study process that included basically the minimum five-year plans; the RMR studies; generation or connections; deterministic planning analysis or planning standards. And we only looked at reliability.

Here we are in 2004 and you can map across over to the right-hand side. And the first four things are the things that we're still doing, the things that we'll be doing in 1998. But there are a list of new things that the ISO is involved in.

In 1998 we were reliability only; in

2004 the ISO is very much involved in pushing probablistic planning within the WECC. That is a tough thing to do. Not everybody's in agreement with that. But it's something that WECC is willing to consider. I think some of the issues that we face is that people don't really quite understand what probablistic planning would do to them with regard to the type of transmission requirements that they would need.

Now, that's not to say that we don't do some probablistic planning today, which we do. We have some criteria that's in place. But mainly it's there to address lines that are, say, in a common corridor or common rights-of-way, where transmission needs to get built. And if you can go through and show that the overall outage history is very small, then you can be granted what we call an upgrade, which would be if you are required a level B, then you could be require level C performance level in the planning standards.

So there is some probablistic thinking going on right now It's just a matter of can we expand that to something that's broader than that.

Kerry mentioned the economic studies,

the -- economic stuff, the teamwork that's going on. The ISO is very much involved with that. She also mentioned the deliverability studies. The ISO, I guess Robert Sparks, who is on my staff, has really been the primary person that's been involved with that. He's spent a lot of time looking at the PJM model, which is where the ISO's current context for deliverability has come from. We've put that on the table for people to review.

Obviously the ISO has some strong feelings about that, but there isn't any reason why we can't have strong feelings about it. But, it doesn't mean that that's what will get done. The fact is that it's on the table and we think that it needs to be. And I think people are in agreement with us. So, now we just need to work through a process to get to someplace that everybody can be in agreement with that.

And then subregional planning, much like Kerry had some things that she was very much interested in, subregional planning is something that I am very interested in. And I think it is an absolute key process that we need to be involved in.

The ISO, in conjunction with a

representative from Arizona, started the STEPP process a couple of years ago. It's an extremely successful process that was actually built off a project or process that they called CATS, or the Central Arizona Transmission Study, which was something that I was involved in when I was in Arizona prior to the ISO.

But the concept of bringing people together to talk about what their needs were, to see if you could find some common threads about how you could build transmission infrastructure that would be meet both generation and transmission and load-serving needs. And that, of course, was brought to the STEPP process.

The Northwest has initiated their process. They call it NTAC, which is the Northwest Transmission Assessment Committee. The Rocky Mountain region also has a process they started out, which I think it's called RMATS, which is the Rocky Mountain Assessment Transmission group.

The ISO is involved in all of those. Terry Winter believes it is an important aspect to the long-term planning for California. He believes that the ISO has a role to play in those.

And he wants us to be involved in those things. And so we are. And we think it's the right thing to do.

PRESIDING MEMBER GEESMAN: Where does the protocol adopted by the Western Governors Association fit into that in your mind?

MR. DeSHAZO: That's a question that I really can't answer. I don't know what that is, to be straightforward with you.

The overall summary, I just listed here the people that the ISO works closely with. And I think the point on this slide is that we work with a lot of different people. We hope that we work well with all of these different folks. We certainly believe that it is of great importance to California and our transmission system development that we do this. And we're very proud of our involvement in these different areas.

And so if there was ever any question that we were sort of focused on California, I think that's a misnomer. We're not. We're very much focused on the outside. Some would say maybe so much so that we're not enough focused on the inside. I might have a different opinion about that, but nonetheless, we do involve ourselves in other areas that would have impacts on us.

Now, I thought I would throw this in. What's interesting is I've heard this word, you know, balkanization, pop up a couple times. Now, I don't know if I'm just being called out, or somebody's calling me a name or whatnot, I --

(Laughter.)

MR. DeSHAZO: -- think it's something I need to think about a little bit more. But I can think through this and I think that that is really probably a very true statement, from a certain point of view.

But I've been doing transmission planning for quite awhile, and there's probably some parts of that that may be a little misunderstood with what the intent is. And I think that the ISO needs to take responsibility here for this.

When we talk about expansion planning process it's a stakeholder process. It's meant to be something that you bring into the public. And I mean the bottomline is this is how the PTOs get their transmission plans in front of the public. This is how they come forward and show, and tell people, this is what we plan to do in order to meet the reliability requirements that we have. Now, there's economics thrown in that, but basically it's reliability.

And that's fine, and I think that the ISO, and I think the stakeholders and the PTOs, I think they're doing a very good job. And I think the process is working well.

But there's a missing link here with regard to what transmission planning really could be, or the expansion planning process really could be. And that is the opportunity and the forum for those that have an interest in seeing something done, to be able to bring their projects to the table and say I think this has value; I think this would be worthwhile to the California ratepayers; and I think it's something that I would like for you to take a look at. And that's what should be done.

Now, we're not asking that they get free interconnection studies; that's not the point. The point is that we want to try to provide a forum where people can come to the table and present their ideas about what they think; if maybe they've got a better alternative transmission line; or a better alternative to an upgrade.

A lot of times, at least in my experience, just the fact of somebody coming to the table with something sometimes will start a thought process that you may end up better off than where you were before.

I believe that to a certain extent the ISO's probably failed in that extent. And I think that that may be in terms of how we look at how the process is working today. It's not as good as it should be. And I would agree that it does need to get better. And I think that the processes you have going on here, and the questions and the issues that you're struggling with is one way for that to occur.

Of course, we do the generation interconnection process. It's undergoing change because of the FERC order in 2003. RMR is like the poster child, you know. It seemed to be a good idea when it was first developed, but it's kind of hung on and hung on and hung on, and I agree, it is time for something to be done.

The ISO is opening up a stakeholder process to take a look at this. I don't know where this will go. I know that there are a lot of issues out there with regard to RMR. Should it be an annual contract; should it be something longer than that. We're kind of stuck in a process simply because it's approved by our board. That's what everybody has agreed to. And we sort of begrudgingly go through this every year.

But the bottomline is the system has local error reliability needs. And if you don't do something to decide to locate those and determine what those are, you basically are going to be left with a situation where either units maybe are allowed to retire without any suitable replacement for that. Or that you have market power issues in place. Or reliability constraints that are not being appropriately addressed.

Here's another thing where I think the expansion planning process can be improved. PG&E has been working very closely with the ISO on these. It's to sort of integrate some RMR thinking into their expansion planning process. Okay.

What we want is that -- why do we want to spend, you know, x millions of dollars on running a generator if I can go -- and that's an annual expenditure that you make every year --

that I can go and spend, you know, some money on a transmission fix that's maybe over 30 or 35 years, but it makes this other thing go away.

And it is absolutely important, especially at least in terms of my group and working with PG&E, and I believe that they are in agreement with this, is that there's some things that can be done that can help reduce the overall RMR requirement for the area.

Now, having said that, I would also say that not all the areas fall in that same sort of a category. Southern California Edison's system, for example, it's almost like too good to be true. They've got an extremely well built transmission system. RMR shows up as a need, but the question has popped up, is it really related to RMR, or is it really related to load growth.

So, there are issues that are out there that I think need to be addressed. And so we believe that it's appropriate that we need to open that process up. There's other things that are going on right now, both within the PUC and the CEC. I believe the timing is right. And so we're going to start to do that. The team effort which has been mentioned, deliverability and, of course, the ongoing subregional planning efforts.

Areas of improvement. I think we talked about most of these this morning. I had mentioned something about the buss level load forecasting, something that Armie Perez has brought before you in the past. That I think the CEC is very good at doing this stuff. The thing is, is while you do the aggregate part, I think the term that might have been used not too long ago, was granularity -- when you talk about Jefferson-Martin I can tell you that the load forecast that was used to determine need is an issue, it's a big issue.

It turns out for this project, because of its need, you could fall down to the low load forecast and determine that this project is needed by 2006. That's great for this project. The problem that I have with that is that if you're at the low load forecast and you're just barely getting there, what if the load is higher than that?

With the projected load for 2003 in San Francisco was 900 megawatts. Our peak was actually 906. So, here you had a low load forecast of 900, but you had a peak that was slightly above that. That, to me, is on the wrong side of the fence when it comes to trying to plan a transmission system. I think, as a planner I think you would want to rather be in the middle so that you could have some margin on either side.

But you have issues that come up, well, you're going to have more capacity than what you need; and so you need to try to time these things in the best way possible. It's all great to talk about, but the ability to actually accomplish that is difficult. And so we hope that there will be some good debate about some of these issues over the next coming years.

PRESIDING MEMBER GEESMAN: On that question, since you raised this at the energy action plan meeting that we had, oh, a month or six weeks ago, Commissioner Boyd and I have taken that up with our staff. And indicated that at least from our perspective as the Committee responsible for the next cycle of our load forecast, the 2005 cycle, that we would like to see the forecast disaggregated to the lowest level that the staff feels has some methodological integrity to it, so that it better meets your needs.

And I think we've conveyed that as

forcefully as we can. The comeback that we get centers on, well, will we have adequate precision disaggregated down to the buss level. And I think the staff's initial belief is that based on the resources that we've put into the forecasting process, the answer is likely to be no. But they agree that somewhere below the surface area aggregation that we currently do, it is achievable.

I guess my underlying question is, is there something wrong with the permitting processes that we use that imputes more precision to these tools than the tools are capable of producing?

MR. DeSHAZO: Not to my knowledge. I think that the PTOs are responsible for doing that today. I think they do a darn good job of doing it. They've been doing it for years. They have the tools, they have the capability and they have the expertise and knowledge to do it.

But for some reason it continues to come into question. Armie's position, I think, has been wouldn't it be nice if you had a state agency doing that. That maybe brings that credibility to the table for what it's worth.

PRESIDING MEMBER GEESMAN: I think it's credibility, and I think it's legal significance, as well. And I guess my believe would be that if the PTOs can provide an adequately reliable forecast down to the buss level it's beyond my comprehension as to why we can't. So, I mean that's helpful to know.

MR. DeSHAZO: Well, Mr. Chairman, I -- and I understand that this is a difficult thing. The fact is, is that you're even entertaining the notion is a great step forward. I'll pass that on to Armie. I may get a hug out of it for that. But, you never know, but --

PRESIDING MEMBER GEESMAN: Well, I'd actually turn that around because I think the analytic tools that we develop in our process are of questionable value if they're not of beneficial use to you and to the PUC and to the PTOs, as well. I mean there's no sense developing our own approach or our own methodology and putting our name on it and saying, well, that's the way we do it here, if it's not useful to the primary users of our output.

MR. DeSHAZO: I wouldn't want to lead you to believe that the information you provide is not useful. The ISO does use it. But not -- it helps us in terms of the overall aggregate and the statewide load forecast that we do.

I think that your information is used in the summer assessment. There's a lot of work that we do internally that goes into that.

But for transmission planning, for going in and establishing need in order to fit with our models, that if we can find a way to break that down somehow so that we can get that in and bring that credibility into that, then I think that that would be a great thing to do.

We want to continue to talk with you about that. I don't know that Armie has talked to the PTOs about this, although he has mentioned it to them. But I think that at least if we can get the conversation started and see where we end up is a great step forward.

PRESIDING MEMBER GEESMAN: Questions for Gary? Or should we hold questions really until the end when everybody's had a chance to speak? Why don't we hold questions then and move forward.

MR. DeSHAZO: Well, actually I had one other slide.

PRESIDING MEMBER GEESMAN: Okay. Sorry

for interrupting.

MR. DeSHAZO: That's okay. You'd asked some questions about consequences of an action. And as I looked at it a key thing that comes to my mind, obviously, is the failure to meet our mandatory reliability planning and operating standards.

Can end up in insufficient transmission capacity to serve load, which could result in load shedding or generation dropping. Both have dire consequences if done at the wrong time.

I believe that there are overall increased ratepayer costs that come from that. You either have uneconomic dispatch that's required in order to make the existing system fit. Equipment maintenance is required but becomes much more difficult to do. We face this in the City of San Francisco today, where you simply just put customers at risk because you do have to take stuff out of service in order to fix it.

The just-in-time thinking that comes about from this is that well, let's build this such that just when we need it it'll be in service. And I would challenge those to reconsider that kind of thinking with regard to transmission. They bring, I think as Pat said earlier this morning, they bring in a large block of capability at one time. And the intent is you don't use it all at once. You're going to use it over a period of time. And if you've done your integrated planning and your coordinated planning well enough you can use that very well.

And then obviously, to me, there's a value of service here which, when you look at it from a ratepayers' side, are they getting the service that they're paying for.

Thank you.

PRESIDING MEMBER GEESMAN: Thank you, Gary. Next up, Kevin Dasso.

MR. DASSO: I have some slides that will refer to it. While I'm waiting maybe I can at least share a perspective on the load growth issue.

Having been a veteran of three CPCNs in the last three years, and actually one that's not yet completed, it is one of the first things that folks opposed to a new transmission project go to; and the importance of having an independent validated by an agency perhaps that's not perceived as having a stake in the outcome is valuable in that proceeding.

Before I get started on the actual list of projects I just wanted to mention that PG&E has been investing heavily in its transmission system. Over the last four years we've invested about $1.1 million in the transmission system; and we have plans over the next five years to invest another $1.8 million.

We have just about -- at all times we have approximately 100 transmission projects that are in various stages of development, either in construction development or in the planning stages. So there's a lot of activity taking place in PG&E's transmission planning, development and construction area.

For purposes of today, though, I'm just going to highlight a couple of key projects that I think warrant maybe being called out of that list. And that would be this slide here.

The first area -- many of these have been touched on already, but I'd just like to provide a little bit more perspective on them. These are short-term projects that are in development now.

The area of -- the way I've organized

this is the area of the project, and then the consequences. So I'll sum up the consequences here as opposed to doing it at the end.

The first area is the San Francisco Peninsula. There's been some discussion of that today already. The key project that we're looking at there, we have several projects that are being developed but the key one is referred to as the Jefferson-Martin project. This is a new 230 kV line extending just about the length of the San Francisco Peninsula.

The second area of focus is the Greater San Francisco Bay Area. We have two key projects that we're looking at for development in the near term. Basically both of these are proposed to be operational by 2005. The first is the Tesla-Newark 230 kV line, which is essentially a reconstruction of an existing 230 line. And the second project is the Moss Landing-Metcalf 230 kV line; also a reconstruction of an existing line.

In terms of the consequences of those two projects, or excuse me, those three projects, are the consequences of delay or inaction are continued reliance on inefficient, aging fossil generation located in San Francisco, as well as the Greater Bay Area.

And then essentially I guess as a worst possible case, no action. We would end up with -- we being the collective we -- would potentially be faced with having to install additional NOx reduction or other types of capital investments on really outdated generation, generation that should be replaced or should be retired, as opposed to being retrofitted.

PRESIDING MEMBER GEESMAN: Now, will those two upgrade projects require CPCN?

MR. DASSO: The last two, the Tesla-Newark and Moss Landing-Metcalf do not. They're reconductoring projects on existing tower lines. The first project, Jefferson-Martin, does require CPCN.

PRESIDING MEMBER GEESMAN: Right, right.

MR. DASSO: There are some other projects I wanted to touch on where we are adding additional transformer capacity which is addressing a different way, such as a new planning criteria that's being adopted now under the ISO and various industry standards that allows essentially the addition of transformer capacity to eliminate constraints in the event that we have a transformer loss.

The consequences of delay on those projects are the potential for load shedding in some very limited circumstances. Each of these go through a test to verify the value of service, the benefits to customers to avoid that outage, compared to the capital cost of making the upgrade. These do tend to eliminate some of the smaller pocket constraints that we do have around.

DR. TOOKER: I have a question. What kind of schedule do you expect or have you had to date on the two upgrades?

MR. DASSO: Excuse me, on which upgrades?

DR. TOOKER: On the two upgrade projects. What timeframes have you pursued those under, and when do you expect them to be online?

MR. DASSO: Both of those are expected to be operational 2005. They were originally proposed in our 2003 transmission expansion plan. For upgrade projects like that, typically we're looking at about a two-year cycle from initial proposal and adoption and approval by the ISO to actually construction completion.

DR. TOOKER: So there's a lot more

certainty in those projects.

MR. DASSO: There tends to be. There's still some uncertainty, but by and large you don't have all the uncertainty associated with the environmental review and permitting aspects. Not to say that there aren't environmental issues, but they are much more easy to manage.

I'm going to shift to the next slide, if I could, and shift the focus on renewables. PG&E's been an active participant in the CPUC's proceeding on really coming into compliance with the renewable portfolio standard, the transmission plan associated with that.

We developed an expansion plan along with the other IOUs that we filed with the Commission last year, which essentially provided a fairly significant amount of information about the transmission upgrades necessary to support the RPS. The plan was developed without regard to which project would actually go forward, and even who actually used the output from those projects. It was essentially a reconnaissance level plan. It gave, you know, a sense of the types if this development does occur what would be the expansion necessary. And then it provided a fairly preliminary expansion plan.

The projects that I talked about in the first page, the Jefferson-Martin as well as the other 230 projects, the transformer upgrades, all of those are complementary to projects that were identified by this renewable expansion plan, but not sufficient in order to meet the RPS.

We're looking at an additional investment of between $150- and $250 million in transmission projects that would be needed. That's exclusive of costs associated with generation, gen-ties.

PRESIDING MEMBER GEESMAN: So these are the network upgrades that you would envision.

MR. DASSO: These are network upgrades, and also there's at least one new line that's proposed.

One of the challenges here is that looking at the cycle time for a CPCN for 230 kV projects, we really need to get started now if we're going to try to accelerate certainly any coming into compliance with these requirements; and yet we don't know which ones are going to be -- which renewable projects are going to be built. So there is a gap here.

I guess for planning purposes we assume about five years from conception to completion of a project that requires CPCN.

In terms of the short-term and long-term relationship, on the last slide, our current plans are really a no-regrets type of strategy. That projects that we're proposing really work under any of the scenarios that are described. And there is a fair amount of uncertainty, particularly with respect to utility procurement plans, energy policy and so on. The projects that we're proposing really work under any of those scenarios.

As I mentioned, all the projects are complimentary to future scenarios; particularly the internal Bay Area projects. If you look at a significant renewable component in the procurement, these are necessary in order to get the renewable energy into the load, as well as meeting reliability requirements.

And then last is we're continuing to look at longer term. And by and large we're looking at ten-year horizons in our assessments.

DR. TOOKER: Where does the RMR focus that Gary was talking about earlier fall into all this?

MR. DASSO: Generally we're trying to incorporate that into our basic expansion planning process. So to the extent, for example, the projects that we listed on the -- the projects that I highlighted, those all have RMR benefits. And so -- the RMR reduction benefits -- we're able to eliminate the need for RMR generation by completing those transmission projects.

PRESIDING MEMBER GEESMAN: Thanks, Kevin. Pat.

MS. ARONS: I have a presentation but I'm not going to try to take the time to get it up and running on the projector. So I'll just talk.

I want to go back to this morning where I don't think the question was asked what steps need to be taken in 2004 and 2005. I want to make sure I get my issues in on that. This is really where my priorities are.

At the last panel that we had in November I raised the issue of the air conditioner stalling problem from Edison's perspective, and we really need to focus and make it a priority in getting appliance standards for single phase air conditioners, requiring them to have under-voltage relays.

It is a real danger on the Edison grid, that as long as it's a problem that the grid can withstand it's a self-correcting problem. When the grid can't take it anymore everything goes black. And we've looked at a lot of different ways of trying to handle the issue, and the most elegant and simplest is one that does require the CEC to take that on as an issue. And that is an under-voltage relay. So legislation or appliance standards, whatever you can do is, I think, of imminent importance. And I don't want to forget that.

PRESIDING MEMBER GEESMAN: And let me commit to you that I won't allow it to be forgotten. After the November workshop I did speak with Commissioner Rosenfeld about that. And I know he had some contact with Edison over the question, and I simply have lost track of where it ends up. But I will circle back and determine that that's being properly addressed. And I thank you for bringing it up again.

MS. ARONS: Thank you. I would like to encourage the CEC to reinvigorate community outreach activities. There was an energy aware planning guides that were prepared; there were two of them prepared in the 1990s.

And the first focused on energy use issues; and the second focused on the energy facility licensing. And these guides were useful to local county jurisdictions in encouraging their review, their expeditious review of permits for electrical facilities and siting; and encouraging developers to look at economic alternatives, as well.

And they were fairly enduring documents. But I think that what the CEC would be well served in doing is going on a campaign and reconnecting with those jurisdictions, making sure that they are being used and employed.

I'd like to also focus on the whole issue of corridor planning and developing what I'm going to call environmental perspectives on new transmission lines. We have a very valuable document with the statewide transmission plan that was prepared for renewable resources. And there's so much that can be done with that document today before we ever decide what gets built.

The first thing that we should be looking at is there are a lot of biological databases, GIS databases, cultural databases that map out sensitivities. And these databases are often enhanced at the time that you have a particular facility in licensing. And now would be the time to take a look at some of those databases and spend money where you think it might be possible in the next 10 to 20 years to build transmission to improve data gathering; put in data that you know is there so that we can begin to develop a preliminary environmental perspective.

You can also leverage that work to look at preparing preliminary perspectives on environmental mitigation; doing statewide strategies for how you're going to mitigate new transmission. And you can also come to conclusions about feasibility in terms of where population is, where growth is expected to be, where housing starts are currently mapped out. You can begin to deal with the whole issue of land use planning, not in a way that requires you to directly decide land use issues, but just in terms of factual information, and developing a perspective of feasibility.

So those are kind of mapping out my high priority issues for things that we should be looking at in the next two cycles of the energy plan.

The challenges. Like Gary DeShazo, I changed the problem term to challenges. What are our challenges in the short term on transmission. And within the next five years we have our annual ISO assessment that looks at particular projects. We have a number of projects -- actually, we have very few projects, mostly driven by load growth requirements.

We have a new transformer in the antelope area serving load growth in Lancaster. We are doing what we call a split of the subtransmission system. Our philosophy for planning and developing our grid is somewhat different than PG&E and San Diego, in that we have a backbone high voltage system of 230 and 500. And we have radialized subtransmission and distribution facilities that, because of that structure that we plan into the grid, we're able to roll load as we have failures. So if we have a 115 line failure we're able to roll load between distribution facilities and so forth. So we have a slightly different philosophy for how we plan the grid.

It's a fairly redundant philosophy, as well. And we've tried to do our best in keeping up with the load growth requirements. So we have a system in the Devers-Mirage area that the 115 line, because of historical reasons, was developed to operate in parallel with the 500. Load has grown to such a point where we're going to radialize and split the parallel 115 lines into two radial systems with the capability of rolling load between the Devers and the Mirage -- source levels.

We have new generation interconnections that are driven either by market generators or by renewable procurement requirements. Tehachapi, as you've seen, is a project that's been cited a number of times. But I'd like to point out that while there has been a lot of focus on Tehachapi as a transmission project, that was really one of the earliest of the renewable projects that Edison began to look at. And we did it in advance of the statewide plans being developed.

But if you look at the Edison statewide plan we have facilities on our North-of-Lugo system to access geothermal in Nevada, in the

China Lake area. We have transmission that was necessary to be able to access geothermal in the Salton Sea area.

So we have a number of areas around the Edison system which has quite a bit of the renewable resources that were identified in the statewide plan. We have transmission plans for all of that.

Tehachapi, while it got out of the gate a little bit earlier, really is part and parcel of the procurement picture. And the decision of when to build Tehachapi really needs to be part of the procurement decision, itself. Part of that is the challenge that we have in licensing a project where the northern terminus of the project is not well known. Until we know exactly where the generators are going to be located, and what the electrical facilities are that have to be built specifically, even on the 66 kV collector system, trying to license a somewhat ill-defined project from the southern end might be fine; but at the northern end you get into a real lack of what is it that you're really trying to do.

Well, that's true of any renewable project when you try to license in advance of knowing what generation you're trying to interconnect. You do get into trouble. So I think we need to be cautious about trying to put a project out ahead of the licensing without really knowing what it is we're trying to procure.

DR. TOOKER: Why was that not a problem with say geothermal?

MS. ARONS: Which geothermal project are you talking about?

DR. TOOKER: You had said that you have existing transmission support for renewables in the Edison area, including geothermal in Salton Sea and --

MS. ARONS: I was talking about the statewide transmission plan that was part of the CEC's statewide renewable procurement identification. We haven't started licensing any of those projects yet.

But because we have those plans fairly well defined, along with the renewable resource, we have an opportunity to begin to do preliminary licensing work on that, on the projects that we're -- and they're only transmission concepts. but it gives us an opportunity to answer questions like where do we think we'll be building transmission.

And what can we do today to facilitate the construction of that transmission sometime in the next 20 years, if necessary, to facilitate interconnection of those particular renewable resources.

We have our new Devers-Palo Verde number two project. We expect imminently to be delivering our technical studies and our economic studies to the ISO. We'll be looking for the ISO's review and approval of that project prior to submitting it for licensing with the PUC. We expect that that project will undergo a high priority process at the ISO. And we'll wait and see what findings they're able to make.

I think as far as the short-term solutions that we've got, I mean we feel -- by the way, Edison has focused on, for the last five years that the ISO has been in operation, we've really made it an action item for ourselves to try to manage the RMR conditions that existed on the Edison grid.

We, when the ISO was created, had over 6000 megawatts of generation under RMR contract. And through a series of grid additions, including voltage support, capacitor additions and some line reconductors and transformer additions, have been able to manage that number down so that we're spending, I think, less than $30 million a year now on RMR for our service territory.

The problem that we get into is our RMR levels are so low what's really driving that, we think it's load growth that's driving that. And it may not necessarily be a true RMR condition. But we continue to grapple with the ISO on those issues.

I think just as far as the short-term solution I think that for me it really comes back to a CEC leadership and community outreach, and deciding how we're going to do energy facility planning, in particular. And really reflecting societal preferences in how we go about doing that. Through corridor planning; through incorporating in city long-term plans; provisions for energy facilities, whether it's corridors or distribution facilities, as well, we think that is really where the roots of the transmission should reside, a transmission vision should reside.

A plan for developing the electric grid, as a whole, transmission and distribution should be rooted in a community planning process. For us, that's a very important objective that the Energy Commission should exercise leadership in.

So, thank you.

PRESIDING MEMBER GEESMAN: Thanks, Pat. David Korinek.

MR. KORINEK: I'd like to address what I feel is the most immediate transmission problem in the state, and that's that our licensing process is broken. Even casual observers of the process in California quickly come to that conclusion, that the licensing process in California is broken.

As I think about that and the causes of that, I personally believe that one of the causes is that the state has lost a concept of what is the public good. SDG&E, as PG&E, is also a proponent in various CPCN applications over the past couple of years. And that has been an example of the process that I'm talking about, and the flaws in the process.

When we bring a project forward and make a decision to submit an application for a CPCN we take that as a serious decision. We don't arrive at that decision as a proponent unless we believe the project is in the public interest.

Contrary to what some of our critics sometimes accuse us of, we do not bring projects forward because we feel they are in the corporate interest. It's a much more serious decision than simply deciding is a project in the corporate interest.

So we're making a decision to proceed once we feel that the project, and the ISO's concurrence of the project, is in the public good.

I appreciate Kerry Hattevik's presentation earlier this afternoon about the efforts that the PUC is currently making to fix problems in the licensing process. But as I look at her slides it appears to me they all have to do with the need side of the equation. I didn't see anything in the measures that she addressed that deal with the routing side of the equation. And the licensing process involves both. So I appreciate the steps they've taken, but they do not go far enough.

Certificate of public convenience and necessity. Interesting example of how that process is broken is our current Miguel-Mission number two proceeding. Both SDG&E and California ISO have demonstrated that that project costs the consumers of California, or I should say that that congestion problem costs the consumers of the State of California some $40 million to $50 million a year.

Even the CPUC agreed with that finding in the AB-970 proceeding. And as a result of that, we filed for a CPCN in June of 2002. Those costs continue to accrue to consumers, and we're now in April of 2004 and we still do not have a final environmental impact report for that project. And the bill for $3.5 million a month to the consumers of California continues to come in month after month after month. Our licensing process is broken.

I also think about the local community role in the process. It appears to me this is another area where the state has lost a vision of who is the public and what is the public good. The public is not just the communities that are along a proposed transmission corridor. They are part of the public. The public is the people of California. And I'm concerned that it appears in our licensing process that some of our licensing agencies have been unable to see the difference between the two.

At the current time licensing in California is still a California process. But I'm concerned that if the process remains broken, and if the process cannot be fixed by Californians, that what we're facing is a federal process, the need for a federal backstop to a broken state process.

I believe the future is in California's hands. We have a choice to make the process work and address it as Californians. We have a choice to let the process continue to be broken and defer to a federally assisted or mandated licensing process. I would rather see the process stay in California.

Those are my thoughts.

PRESIDING MEMBER GEESMAN: Well, I'm going to resist the tendency to respond in any detail because I've been sworn to more diplomatic behavior here in the last couple of months. But I do strongly endorse and embrace each of your remarks, and think that your company and your ratepayers have borne the burden of a state government's indifference and incompetence in this area for the last several years.

I'd actually like to see your statement

transcribed and included as a bill stuffer for every customer's bill in California, because I think it's a problem that has not received enough attention. I think slowly state government is starting to understand, and I'm hopeful that we're able to correct some, if not all, of those problems in the next few months ahead. It's a daunting challenge, and there have been a number of people bearing that same banner for quite some period of time. It's difficult to get the message across.

But I thank you for those remarks, and want to let you know that certainly this Commission, and I think a lot of others in state government, share your views.

Morteza.

MR. SABET: I don't know if I can follow Dave on that note. But I do sympathize with his passion, as well as Pat's. I think that's an issue that seriously need to be addressed. That's no way to run a railroad.

Just want to give you an update, as requested. Don't ask me to give you an update for the problem we have -- I wasn't prepared to talk about the renewable and other issues, just the

Sacramento area and the Path 15, if you allow me to do that, I appreciate it.

Western just -- bear with me, Western is a wholesale power and transmission provider in the 15 western states. We don't have any end-use customers that we actually control the load of, including Reclamation. We are basically spread in 15 states and geopolitical diversities of --

The Sacramento or Sierra Nevada region of Western is basically over the old watershed boundaries on most of our transmission is in northern California, basically north of Tesla. We have customers in Nevada and customers beyond our transmission boundary on PG&E, and some in Edison's territory.

The Sacramento area transmission problem was identified back in the '80s when Rancho Seco was basically up and down. And SMUD basically was going through the change at that time. Because we were planning the system with or without Rancho Seco in every study that we did.

Subsequent to that and the load growth of the 1990s had aggravated that situation even more because SMUD annexed the City of Folsom to the east. And as you well know, the load growth towards the north and the south, as well as the eastern part continues to grow.

We took the coordinated planning notion in the early '90s after the Energy Act very seriously. Opened this project up to the world, basically, asking others that were accusing the utilities, basically, naturally planned for transmission line, to come up with alternatives to fix the area problem; i.e., either by load or resources.

Lo and behold Calpine basically showed up in 1977 and we definitely encouraged them since they were willing to locate the generation near the load center. And at a time when licensing which is the first merchant power plant in the state came before the Commission, Western recommended the transmission reinforcement for that plant be staged.

The stage one for remedial action, because Calpine very clearly articulated they're not in the transmission business. Stage one basically had local supervision or remedial action control that automatically look at the line loading, and the generation output at just the two together. So we basically maintained the line loading within the reliability criteria.

Subsequent to that we also looked at a numerous dose of blue lines that you see, 230 and 500 kV alternatives. And during this time, after Calpine went online, two other power plant developers came to the area. But unfortunately by the time we got the principal all set up, they went belly up. And we are back to where we started.

The area utilities namely in this area base is SMUD, which is about 90 percent of the load; and Roseville, which is the remaining 10 percent. PG&E transmission is around the area, is not that sensitive to the area load that is composed of those utilities.

If you look at this diagram, actually compliments of the Energy Commission, the SMUD is right in the middle, and those areas I just highlighted for you to show where the generations that are being proposed coming in; that's Cosumnes Power Plant on the southeastern part of the county, and Roseville's Energy Park, near City of Roseville.

Basically the area is an electric island with two connections with PG&E to the east; two with Western from south and the north.

Due to characteristic of the system during the summertime these lines, are about 100, 200 miles long, are loaded beyond their -- loading. The area imports about two-thirds of their need from outside. So we do have an acute thermal overload. This year I think we have like 21 or 22 that triggers to the ramping of the generation. I'll disclose that in a little bit.

That basically there are 20 or 30 triggers that you know in advance that causes basically the system going to orbit, that you have to either shed load or shed generation to manage the reliability. And we are very conscious of that, and I commend SMUD for doing an excellent job to recover from Rancho Seco by all the short-term mitigation. But we are running out of head-room; not a lot of room left on the system.

In addition to that, we are working with the Commission Staff, and we just installed these real-time line monitoring devices on the lines on the north, and will do soon for the lines to the south, to make sure how much we can push the system. Do we actually have the adequate safe margin in our transmission lines to push the system even higher.

So, the environmental impact statement that we did started with Florida Power and Enron being at the table at the time. We were basically going to fix the transmission in the area on a participation or coordinated fashion with all of the load-serving entities and the generator in the area basically pitching in and sharing the cost of the burden, as well as the benefit.

But unfortunately, by the time we got that going, they left the scene. But we did, nevertheless, complete an environmental impact statement; the details of the timeline is there; and we have an extensive site on our website that you can look at that has all of the information in it.

Basically the area, at least in the near term, we need to build about 26 miles of double circuit 230 line to eliminate the remedial action that is going to be more and more frequent if nothing is done. Because as the area load goes up, which is about 150 and 200 megawatts a year, we have to bring this other generation down accordingly to basically prepare ourself for post-contingency operation. Otherwise the system may not be under our control.

So that is why it is needed to build those two circuits, as well as reconductoring our lines from Alberta all the way to the south. This is about $60-, $70 million project, but we have yet to find a source for financing because of the particular situation we are in, Western, as a federal agency. But we are working with our customers, as well as others, to look for solutions for this.

But this is by no means is a long-term solution. This is only short term because by the time we complete the $70 million project we will be in exact same situation we are in. We have no head room in the transmission for additional load growth.

We just recently studies longer term option that we have studied in open forum with all the utilities in the area, as well as the generator. If generation is basically located within the area, anywhere around the Sacramento area, obviously that's the best solution. But if that cannot be located in the area, transmission is the next best option.

And just recently we looked at an option that we had looked at a few years back, like in 1999. Looping of the Table Mountain-Tesla into our Elverta substation, which is just north of the airport. It's about ten miles line. It will be just like putting a 620 megawatt power plant right there at that point. Granted, that is not the end of it. You have to fix some of the upstream and downstream, and also address the greater grid impact. But, nevertheless, that's one other solution that needs to really be pursued.

Next I give you a short update on Path 15. That project is well underway. We have a really nice site that has all of the construction progress pictures and some video clip, as well. That project is basically a couple three years to put us in the loop with the project. And it is going to be completed by the end of the year.

As you all know, Path 15 is the only link of intertie from Portland down to southern California that has only two lines. This contractor is using basically both the helicopter operation as well as the ground crew to install. We have two types of structures, lattice steel and then single shaft in areas that we had to mitigate for environmental, or the access was an issue.

They're actually pretty slick. Since I was involved in the construction of COTP, the work is staged very well; there's a great deal of efficiency in construction and fairly safe.

They stage the circuits -- the towers in line, next you know, it's on. And this is basically the lattice structure -- I mean the single shaft towers that we are using in some areas now. About one-third, I think, is tubular steel; the remaining two-thirds is the lattice structure.

PRESIDING MEMBER GEESMAN: Could you elaborate a bit on -- you said there was a financing question on the Sacramento project?

MR. SABET: Yes. Mainly because Western does not have the load-serving obligation, load-growth obligation, only wholesale transmission provider and basically federal power, allocated federal power to public agencies, so we do not have a load growth component in our federal power obligation.

So that basically puts us in the kind of peculiar situation, because our transmission is a bridge between the source and the sink. And we have tried by Congress in their ultimate wisdom have not basically granted us the financial access to do this kind of stuff. But time will tell.

PRESIDING MEMBER GEESMAN: Do you have the statutory authority to enter into a lease with a private party to pay for the line?

MR. SABET: That's what we did with Path 15, I think. But that one was legislated by legislation. It is not an automatic. But I think in the Sacramento area, when Florida and Enron were at the table, we were discussing exactly that concept. That they would basically buy their wheeling upfront, and we'll finance it and we'll basically credit their bill for the services provided. And we're still open to that.

That goes for our customers or anybody. We'll take anybody's money.

(Laughter.)

PRESIDING MEMBER GEESMAN: Thank you, Morteza.

MR. SABET: Sure thing.

PRESIDING MEMBER GEESMAN: Mark.

MR. WARD: I think for the time we'll forego the PowerPoint presentation, but I wanted to give you an idea as to the planning process for Los Angeles Department of Water and Power.

As you know, the Los Angeles Department of Water and Power is a vertically integrated utility, owned and operated by the City of Los Angeles.

We go through what's termed as an integrated resource plan, which the last plan was approved in the year 2000, and is currently being updated, with an expectation to be approved again this year.

Our main concern, of course, is how do we serve our native load customers. And because of that, our focus ends up being native load driven with looking at reliability, and we also look at community concerns, and we also take community input on that process.

Also we try to avoid having too many eggs in one basket, which tends to push out some of our procurement to other regions. And in that particular process we've taken a collaborative process where we joined with other utilities, Southern California Edison, the Salt River project, Nevada Power and others.

And in that approach we've tried to look at local issues versus regional issues. On the local issues, we can take generation, transmission, distribution solutions and we can put them together such that no one problem is considered in a vacuum.

So in some instances we've been able to shift some loads around our system to alleviate some of our local problems. We've also been able to build some local circuits that would probably not concern people outside of our local grid, such as a 230 kV circuit in the Hollywood area. We also built a new circuit in the Van Nuys area, 230 kV to support our loads.

In addition to that, we've been able to take into full consideration the costs of RMR versus generation, and make an economic choice as far as what is the most cost efficient method of supplying transmission issues over on the east side of our system. Our newest repowering will offset one of a 230 kV project that was scheduled for next year. So that project will be delayed as our system loads will catch up with that. Probably sometime in the year 2012 or so.

Also, on a local issue, is that we've had some issues out at Sylmar substation. Those particular issues have, at times, forced us to derate the DC to make uneconomic redispatch to accommodate flow and those types of things. This year we are installing a third transformer at Sylmar switching station; and that will double the capacity out of that station. And we believe will mitigate most, if not all, of the flow issues out of Sylmar.

Additionally, we have participated in the east of the river projects. We've participated with WECC in the regional planning. We've participated with STEPP. We've also participated with WATS, as far as trying to increase existing capacity so that existing capacity can be utilized much closer to their thermal limits.

The question was asked what we believe the consequence of inaction for some of the east of the river projects. Without increasing the capacity for east of the river, we see increased flow mitigation. And by that, I mean we will probably see much more uneconomic redispatch of generation if we cannot get additional capacity coming across the river.

I think it's been pointed out in some of the other presentations that we will also end up relying on an aging infrastructure on both sides of the river, which, while it can be maintained, will subject us to a greater number of outages.

So how do short-term solutions fit as far as the east of the river concerns for Los Angeles? We believe that with the short-term fixes on east of the river, as far as increasing the stability limits east of the river, will give us greater ability to site resources, both in southern Nevada and on east of the river. We will also be able to provide additional transmission access, at least on the DWP system, while the longer term solutions are looked at for getting additional generation into the Los Angeles system.

I wanted to point out excess transmission for Los Angeles is currently posted on the Los Angeles Oasis system. On April 1st, DWP, along with I believe 18 other transmission providers throughout the west, started up an Oasis system on WesTrans, which will provide access to transmission in real time from a multitude of providers all at one site.

So, in conclusion, Los Angeles strongly believes that generation, distribution and transmission solutions should be looked at all at one time to come up with the best solutions.

Regional planning, in collaboration, should begin with our local requirements being met. I think that the local requirements have to be looked at for all participants when you're in a collaborative mode, both for the out-of-state and for the in-state participants.

Thank you.

PRESIDING MEMBER GEESMAN: You came through the 2000/2001 period pretty well, relying on your own resources. So I approach this question with a little bit of trepidation. What do you think state government can do for the City of Los Angeles in the transmission area?

MR. WARD: I think the state government can go back to having a more standardized environmental process such that people can actually get these projects through and permitted in a timely fashion. That the standards are known upfront, such that you're not going into projects, and then halfway through the project finding that there may be some environmental concern that wasn't considered.

PRESIDING MEMBER GEESMAN: Thank you. Jim.

MR. FEIDER: Thank you. I will limit my

remarks to a couple pages of recommendations. I have prepared a written statement for the record, and I'll try to condense, since there was a lot of background set for this discussion earlier today. I would just summarize this morning's discussion from my perspective as kind of getting back to the basics, recognizing that transmission is a long-term investment; and that transmission is there to get the kilowatt hours from the generator to the load. And a lot of the needs and the planning perspective is driven by the resource adequacy that we champion.

A comment was made this morning about perhaps a good share of the transmission isn't under the ISO and insinuated that that was a bit of a problem. I would just observe that colored maps can be a bit deceiving at times. I would like to comment that the Pacific AC Intertie is a coordinated system, including the Transmission Agency of Northern California's portion of the California/Oregon Transmission project.

We are moving forward in a changing paradigm, and just last week PG&E filed at FERC a replacement approach for the coordinated operations agreement of the Pacific AC Intertie.

That agreement focuses on a single-path operator, which we certainly agree there needs to be a single-path operator. But when it comes to the rights to use that transmission grid, the municipal business model is much different than the ISO business model.

We're not saying that ours is the only way to go, but we want to preserve our rights to do so. And we think there is strength in that diversity.

With respect to the short-term fixes, in many respects we'd just say, fix it, damn it, which we've been saying on Path 15 for over two years. TANC would like to have participated in that project, but we couldn't get value for our customers out of it. But we still champion, both politically and locally, the need to fix that project, so we support Western, Trans-Elect and PG&E moving forward. I would also agree that that, perhaps, is an example of a broken siting and permitting process here in California.

Similarly, we have the same approach toward the Miguel substation, and the fact that generation was brought online without a way to get it to where it needed to go.

We think that we ought to continue to develop, and subsequently implement, additional strategic transmission outside the State of California to more robust basins, supply basins, including the Rocky Mountain region, the desert southwest, and potentially the Canadian provinces.

With all the effort that's going on with regard to transmission planning, I'm wondering if there may be a disconnect between the ability to plan transmission and the perspective of a resource supply standpoint. I would hope we could just dialogue with other states, perhaps close the gap between our ability to plan and coordinate transmission, and our ability to plan and coordinate the broader perspective of getting resources to load over that transmission.

We think that the state should encourage and empower those responsible for serving customers to broaden their resource portfolios to include fuel diversity, geographic diversity, renewables and energy efficiency, as well as resource deliverability. The deliverability issue seems to be coming back on the radar screen. We're encouraged by that. It never left our radar screen during the height of the energy crisis.

If I could digress for a minute on energy efficiency and demand side, the City of Redding, as you may be aware, gets a little bit warm in the summertime, and we are a very peaky system. And so our needs, what we could do on the demand side, on the customer side, is different than our brothers and sisters in the municipal area in the Bay Area.

But we are doing what makes sense for us. We're looking at an aggressive program in -- storage to shift load offpeak to relieve the transmission, which will result in some relief on transmission. We're looking at ground source heat pumps in a way that we would help invest in the capital to make those pencil. That also is a more efficient way of cooling and heating our customers' needs.

A couple years ago we took the lead in changing our rebate program on air conditioner replacement, where we no longer will rebate a SEER 12. And we put more emphasis on rebates in the higher SEER where it will do more good. All of those, we think, goes to taking pressure off of the transmission grid.

I'd like to compliment the transmission

planning staff at the ISO. I think they have one of the most talented groups in the country. They do a good job of putting the plan together. But, as I've said before, there seems to be a disconnect in the market model of what it takes to look at this at a comprehensive level.

We think that the ISO market paradigm is at odds with the rest of the west, and those issues will make it harder to plan transmission in a coordinated way.

I would observe that the RMR issue, I believe, is symptomatic of this market structure being somewhat broken. And as my colleague next to me from Los Angeles pointed out, we've been continuing to take a vertically integrated approach towards serving our customers.

We certainly do agree that it would be helpful to improve or streamline the state's approval process for the investor-owned utilities. And as I said this morning, I believe it would be wise to halt the California ISO's MDO2 and LMP efforts; put the brakes on that while we take a hard look at transmission planning on a regional basis.

Also, as I mentioned this morning, other parts of the country have put the brakes on, for example in the State of Wisconsin, as well as the seven governors in the south that recently wrote President Bush to slow down FERC's push for a market-based transmission system.

I would just suggest a word of caution when it comes to application of technology. I would certainly support the latest technological advancements and looking at what it would take to get the most out of our system, but I would be a little careful about squeezing all the margin out of the transmission system so that there is no margin left for Murphy's Law or other nature's law when it comes to statewide heat waves. I would suspect our transmission planners would tell you they typically don't plan the transmission grid around a statewide heat storm. So, technology would be good, but be careful about pushing too hard to squeeze the last bit of margin out of the system.

Let me just wrap up by saying that for the City of Redding and the Transmission Agency of Northern California, the munis, in general, we will continue to plan our customers' power needs, both short- and long-term. We will make appropriate investments in those needs. We will seek to develop a diversified portfolio. We will support strategic transmission development, both within and outside the state, as long as there's value to our customers.

We will continue to take a long-term view and insist that the delivery of generation is best achieved through firm, physical transmission rights. We will proactively seek opportunities to engage in the collaborative actions that can benefit all Californians.

And I want to extend my appreciation to the Commission and its staff for identifying one of the most critical issues and focusing attention again on the basics. Your efforts here today are an important step toward fulfilling our individual and collective obligations to the people of California.

Thank you.

PRESIDING MEMBER GEESMAN: Jim, in your written remarks, at a point there on page 5, where you say, let us use the costly lessons that have been learned at the Miguel substation. I wonder if you'd elaborate on what you think we may have learned at Miguel?

MR. FEIDER: Well, my fellow panel member from San Diego, I think, appropriately pointed out the $40 million per year increased costs to the consumers of California. And, I would suggest that perhaps policymakers were too distracted with other things to focus on concentrating on getting that fixed and in a timely basis.

PRESIDING MEMBER GEESMAN: Yeah, I guess I'd amend your remarks to what we should have learned from the Miguel substation. It was, I think, two years ago this month -- I was still on the ISO Board -- when we approved the Miguel substation improvements; we told there was no opposition to the project at the time. Clearly had a green light. I'm not certain what could have looked like a more attractive project from state government standpoint.

And as Dave said, two years later we still don't have a final EIR. And we're about, I guess, to lose another summer in terms of its anticipated online date. A 30 to 40 million annual projection does keep rolling on. I'm not certain we've learned anything yet.

And I think the challenge in front of

all of us is to avoid having that sort of thing happen again. But we said that after Path 15; we said that, or some of us said that after Valley Rainbow. So, our record isn't real good. And I think we've got a lot to learn from the record that has been developed.

Let me turn it over to the public, though. Are there questions or comments that members of the audience would like to share with us? Hal.

And for our reporter you should identify yourself before you start speaking.

MR. ROMANOWITZ: Yes, thank you. I'm Hal Romanowitz, Oak Creek Energy. And I wanted to just add a few thoughts in that I think the discussion that we had was extremely good and helpful. And, of course, we, maybe selfishly or not selfishly, think a lot of Tehachapi, as we go through the planning process, but I think this whole process has to work very well on a broad basis. And I think that the issues, sort of as we're looking at it, and how it needs to fit in are very important. And I make my comments in that light.

One of the important things that I kind

of gather from hearing here is there is a lot of thinking of the future based on the past. But, to a certain degree, I think we can make more progress by thinking of the future and planning for the future based on what the future is more likely to be. Sort of an oxymoron in the end.

And by this I mean that, for example, and I think that the hell that Pat has gone through for so many years in Tehachapi is very significant, and is an excellent lesson looking into the past. And when you project into the future those same things, it creates an extremely difficult planning scenario. However, that probably doesn't have to be.

For example, looking at how you integrate a significant amount of wind into the grid. With rule 21 in particular, with FERC 2003 now being out, and with the latest version 2003A just being out, and there's an appendix G associated with 2003A that is very significant.

Now, at the present time that appendix G is a blank piece of paper, but it's not going to be blank very long.

And I think the lesson from this is that where wind energy has been, you know, a difficult induction machine in the past, difficult to integrate with the grid, that what is, I think, undoubtedly going to be out there and it may be surprisingly to many people, is a generation technology and capability that is extremely utility-friendly, transmission-friendly. And when you think of integrating that into the grid, it is -- I think it makes the job much easier, for one thing.

So I think that that is very important that we consider that and consider what the wind projects of next year or the year after will be. And those things can be well defined, and it's not magic, it's not isolated to any one entity. And it will be out, I'm sure, very soon from a FERC standpoint. So it will be widely out and should make the planning process very easy.

Secondly, as you look at --

PRESIDING MEMBER GEESMAN: Let me stop you, Hal.

MR. FEIDER: Yeah.

PRESIDING MEMBER GEESMAN: Because I had understood Pat's point to be we don't know if it's next year's wind project, or two years' wind project from now, or five or six years from now.

How does a different technology address that
timing question that she has to face?
MR. FEIDER: Okay, that's a very good point. And what I was trying to say is that I believe it's clear that the wind turbines that will be required by appendix G are very utility-friendly regardless of what they are. So that they're not the unfriendly things that Pat has had to deal with in the past.
And secondly, when you look at Tehachapi there is already very substantial land use planning; there's a defined MEA area; there's a defined resource. And when you look at that and say that if you do a substation one according to the present plan that exists, that is strategically located in not a very bad location. So that you could accommodate virtually anything within the current MEA area of Tehachapi, which is at least 800 megawatts worth of projects; already land-use planned that there is the ability to go forward, I think, with something that makes substantial success possible.
And if we don't go forward with it, if we allow the uncertainties to sit and wait, we are, as a state, going to lose enormous economic

benefit associate with the PTC, which is likely to be phased out not very many years into the future. So that the incentives that are helping wind now are going to start phasing out at some point in the future. When, we don't know. But, that's a significant economic benefit that will no longer be there to be taken. So we either have transmission to utilize it, or we're going to lose those benefits forever.

If we don't have the competition from Tehachapi, which, again, everybody says the proof is in the pudding from the bidding, but what we do all know is that Tehachapi is almost certainly the best resource in the state, the best capacity factor, inexpensive land, good permitting, MEA already in place, so that you can get a large number of projects bidding competitively, lowering the cost of the bid process, lowering the cost of the RPS. And without Tehachapi, without feasible transmission you're going to lose that. You're going to lose significant economic benefit to the state, again.

And the consequence of all of this is that by not pushing forward on Tehachapi you're going to force the RPS to be met by out-of-state resources so that all of the economic benefit that we're doing with the RPS is going to go to out-of-state producers, out-of-state money, out-of-state gain. California will have created the market for people other than Californians. And I think that's less than a desirable scenario.

What I think has to happen is that, you know, the phase one process that SCE laid out for Tehachapi is a good process. I think that, you know, workshop or in other discussions, it would become clear that there are substantial additional benefits to that particular process, or that particular line that will accrue to the state in the transmission planning process over time. So that that plan could go forward with a very high probability of success, with significant gain to the RPS process by going forward.

If it doesn't go forward it's all lost for this time. So I think there is great urgency to it. I think that with some discussion, some back and forth working, that it can be made clear that this can be a general process, not advantageous to any one supplier or that sort of thing, can go forward on an economic basis. And that it can make the planning process work sooner and more smoothly than is generally thought.

So that we strongly encourage, you know, the thorough, long-term planning processes that are being discussed, but we think that in the meantime it's really important to take this one piece and push it forward into the CPCN process as much as possible, because Edison has a lot of their environmental work already done. And take advantage of that work, and maybe build it after the bids are in. But at least get that planning forward so you can have a transmission line probably in 2006, rather than 2008 or 2009, as is likely to happen if we just go the way that we're talking.

PRESIDING MEMBER GEESMAN: And if I understand you, then, you would prefer the Edison phase one approach to the variation on Path 26 upgrades that the ISO suggested as an alternative?

MR. FEIDER: Yes. I think that there's a big advantage to just saying, SCE knows what it's talking about, and has multiple needs for this phase one line it's putting in. And to go ahead and get that going, break it loose. Because you have the transmission planning already underway, the environmental planning already under way.

And the other things that the ISO has suggested are very good suggestions. And there are a number of other suggestions, also, incorporating LADWP and the Sagebrush line and so on. These can all be integrated in later on.

I think that the area is so big and the potential is so large, that you're not going to lose those overall things. But that what we're losing by all debating, you know, which is the best penny to save, we've lost the dollar bill in the process. And that the economic loss to California by delaying, I think, is significant.

PRESIDING MEMBER GEESMAN: But I think I also heard you say that you would actually wait to commence construction until you had a round of RPS bids in?

MR. FEIDER: Or some other way of building the line. In other words, you need to have it, before you can actually commit to the construction dollars, which are the large dollars, you have to have projects online or somebody committed to support that funding.

And I think that there are potentially multiple ways for that to happen. And that if we have a plan that's moving forward I think that there is going to be a way to fill it, from what I can see and what I know of the area. And that to delay the CPCN process is losing the time such that we may blow that resource area out of the opportunity to capture PTC dollars and make it economically, you know, -- I think it's major major dollars for the state that would be lost by delaying.

PRESIDING MEMBER GEESMAN: Okay. Jane.

MS. TURNBULL: Thank you. Jane Turnbull, League of Women Voters. I would just like to ask for some clarification. There's some of us that don't live with transmission as a full-time occupation, even though we follow it as closely as we can.

The topic of deliverability studies has come up today, and that's an area that at least a couple of us are not terribly well acquainted with. I'd like to take advantage of -- here today to try to get some understanding of what is intended with the deliverability studies and what the projected relevance of those would be.

PRESIDING MEMBER GEESMAN: That's a great question, and actually it's a question that

I asked at our aging power plants workshop a week and a half ago.

Gary, do you want to start?

MR. DeSHAZO: Well, actually, according to my wife, my entire life's not about transmission planning, either, although I think when the "honey-do's" come along I'd like for it to be like that.

I think that maybe in concept for deliverability is that if you have a -- if you go out and you go through a resource procurement process where you've got the utilities looking at, well, what kind of resources are they going to need over the next 15, 20 years. And then they go out and they get those, they procure those resources.

You could do that and just assume that if I've got this amount of load that I need to serve, and I'm going to go out, and plus whatever reserves that I need, and I'm going to go get the resources to go do that, you could just sort of deem that whatever resources I get I'm going to be able to use for my load.

But I think that the transmission system doesn't work like that. And so you may go get a resource that's in a location that simply cannot get to the place where your load is.

And so what the ISO has suggested is that as part of that process we need to have some sort of a deliverability standard that we need to meet, such that if you're going to go procure a resource then you need to be able to demonstrate that you can get those megawatts to your load.

And if you can't, then you need to come up with some way to define what kind of transmission facilities are required in order to make that happen.

And in doing that, that sort of fits that into a transmission planning process. And, in fact, it kind of brings to the table the concept that some would suggest that deliverability really is nothing but transmission planning.

The person that I have working for me that's doing this actually spent about an hour convincing me that really this is a resource adequacy question, and has almost convinced me that my last 25 years of transmission planning is I've been a generation planner, not a transmission planner. So I'm having a hard time sort of mixing those two things together.

But there's somewhat opposing views about which one that is, and about where that should occur. I'm not sure that the ISO -- I think that the ISO tends to look at it as a resource adequacy issue, and it needs to be addressed there. But that is yet -- is far from being fully defined.

MS. BERGEN: Just a followup on that. How close were you -- the initial proposal has come in with guarantees of the transmission of that power -- generating power that is being proposed, does that company have to go out and get a contract -- transmission company? Do they have to -- how much proof do they have to provide? How closely are they responsible for that? Do they just come with a general plan --

MR. DeSHAZO: Well, I guess the question is related to if someone can go out and procure the resource, you know, how involved do they need to be with the transmission aspect of that, right.

I don't think there's an answer to that question right now. It's obviously a question. And I think it's going to undergo quite a bit of debate.

From the perspective of the ISO, an example of why that maybe is still out there, and bear in mind that this is a new issue, and it's just come to the table. And so there'll be a lot of discussion about this.

But for the ISO and the system that it manages, you can assume that some of those resources are most likely going to be outside of that. They could even be in another state.

And the question that has come up is for the ISO to consider this resource as deliverable, should it be the ISO's responsibility to assure that there are sufficient transmission contracts in place to move the resources from Wyoming or Arizona or wherever it is, to the ISO-controlled grid.

Or is it just that the ISO should only consider the fact that knowing there's a resource out there, we have import lines that come in, that we want to make sure that we manage our imports on a simultaneous basis. In other words, we want to be able to maximize the amount that we can import. So we probably aren't too concerned about whether they should have transmission contracts to do that. We should be concerned about whether or not we can actually get it into the system.

That's a question -- that's just an example of one of those questions that's out there that is yet to be resolved.

MS. BERGEN: In what way is that different from IOU -- in what way is this process different from what the IOU used to do in its resource planning?

PRESIDING MEMBER GEESMAN: The reporter should note, this is Jane Bergen speaking.

MR. DeSHAZO: Would one of you folks like to -- I mean I've -- they put me first. You know, originally I thought I would just try to meld in somewhere down the line. But sometimes you're the bug, sometimes you're the windshield.

MS. HATTEVIK: Before you answer that maybe I could jump in a little bit on it. Maybe it would help clarify. Because I think I would agree with Gary or the ISO's perspective that this does go down to resource adequacy. And I think you really need to link the ISO's expertise, as far as planning the transmission grid, the engineering on deliverability, with what the IOUs are actually going to do when they go out and procure.

So, to me, those are fundamentally linked. And what I think this comes down to where I think Gary didn't mention is really an issue of cost allocation. Because when an IOU goes out there and contracts for capacity, that capacity needs to be deliverable when the system's at peak. That's my definition of a capacity resource. It needs to be deliverable at peak.

So you need to make sure the transmission system can facilitate that deliverability of power at peak.

Now, what we don't have now is sort of a capacity type rules for the utility to go out and procure under those circumstances, so we have a cost allocation issue. The two generators on the border that are contributing substantially to the Miguel situation, put two generators on the grid, that couldn't be deliverable, and then they get paid for not being able to deliver. They chose not to do their five-year transmission upgrades with five-year credit backs, even though it's probably a pretty sweet deal, because they're getting paid not to have the transmission there.

So there are fundamental problems there; there weren't deliverability criteria there that in the future will be there, I think. And I don't see a world where the utilities would go out and contract with such a generator that didn't have the deliverability upgrades done and didn't have a cost allocation mechanism for that; i.e., if you want to qualify to be a capacity resource, pay for your transmission upgrades.

So, to me there's some real structural problems with -- structural elements to the deliverability upgrade, and then there's some -- you kind of piece it out this way.

MS. BERGEN: Well, if you'll forgive me I'm not, as I say I'm not a technical person. I am interested in --

MS. HATTEVIK: I'm really not, either.

MS. BERGEN: -- governance, however. And I am just trying to get a better sense of where we hook on. I grew up in the old days, and was pretty much involved in this issue in the '80s; knew the rate structure and process pretty well and so forth.

And I understand what you're saying, that in the new setting there are these problems that have arisen. But simply what I'm asking is, that the process that you described earlier of being sure that you can deliver the energy that you've got, whether you've bought it or generated it yourself, wasn't this something that was the responsibility of the IOUs before Cal-ISO existed?

MR. DeSHAZO: Well, yes, it was. And I think if you go back into the '80s the structure was the bigger the plant the better; you know, you try to build. It's basically economies of scale. And then you would find someplace to locate that. And then you'd look at, well, okay, so what kind of transmission then do I need to have in order to be able to deliver that.

And so there would be a lot of technical analysis done that would try to determine that I could actually schedule those megawatts across some predetermined path, whether it be an existing path or one that I'm going to build with a new transmission line.

And as long as I could make that happen, and under peak conditions, or under conditions when the transmission system was highly stressed, as long as I could do that and not adversely impact others, then I'd be able to make that, a scheduling path. You'd usually define how much it was rating, and so I could schedule up to that rating.

It used to be, I think, fairly simple back then. But now life is not so simple. With the advent of all of the gas and the siting of combustion turbines, I think when I joined the ISO in 2001, we had something like 1200 generation interconnection requests on the table. And they were just showing up, you know, by the tens every week.

And I just think that in today's world how we used to do it back then just doesn't work anymore. And even for those that are not within the ISO, you know, where I came from was in Arizona. I worked for Salt River project there. I was there through the time when we had roughly 10,000 megawatts of gas-fired generation that was proposed all at one time, and all at one location. And nobody was proposing any transmission.

And the way that these folks would like to look at something is that, okay, well, I'm going to come in here with my 500 megawatts, but I'm going to assume I'm going to replace 500 megawatts of Palo Verde. So the net impact of the transmission system should be zero, and that's how they would want you to look at the system.

Well, that doesn't work. But that's how they tended to want to do things, as though they were going to come into the market and replace others. And that was a very difficult thing to get through. But we worked with those folks to get together and say, look, we need to define how much the transmission system can handle.

And I think we all know that while the generation got built there's not anywhere near enough transmission capacity in order to get that out. And then when you connect that up with existing contracts and transmission rights, it just turned into a really big mess.

Here, with the ISO, of course, it's the open grid, but it's still something that's difficult because these folks can just literally site anywhere that they want. And I think that we're getting to a point now, as we start into the future, that it's a test that I think is just, it's absolutely necessary in order to be able to find a way to make all of this stuff work together.

If we don't do that, then we'll never be able to get to the long-term stuff. We'll be just mired in just the short-term type things. So we can't do that.

PRESIDING MEMBER GEESMAN: Yes, Miss.

MS. ARMI: Good afternoon. My name is Osa Armi. I'm an attorney at a lawfirm called Shute, Mihaly and Weinberger. Some of you may remember us as the lawfirm representing the community group Save Southwest Riverside County. November, actually, I was here when the topic of discussion was how do you involve the public constructively in planning for transmission projects.

So, along those lines I wanted to respond to the presentation you had earlier from the PUC Staff, and specifically their proposal to delegate need determinations to the ISO not subject to revisiting by the PUC.

I just wanted to make sure this body is aware, notwithstanding some contrary representations by the PUC, that is not a universally accepted proposition. I'm here to express actually quite strong opposition to that idea. Mostly because quite simply the PUC has the clear statutory obligation to do that determination. I see no authority for them being able to delegate that to a nongovernmental entity, the ISO, which has much less formal proceedings available to it. Quite frankly its proceedings are frequently invisible to the public; and certainly more difficult to participate in than those of the PUC.

It has certainly been our experience that the ISO does not do the same high level of evaluation of alternatives and environmental impacts that you see at the Commission, the Public Utilities Commission.

We will be filing comments tomorrow in the OIR opposing the proposed procedural changes. And if that's helpful I'll submit those in this proceeding, as well.

PRESIDING MEMBER GEESMAN: It would be very helpful. And, in particular, if you could address those in the context of CEQA requirements, I think it might be quite helpful for those, a lot of different governmental agencies looking at this question.

A similar question came up when this Commission and the Public Utilities Commission and the California Power Authority were considering the energy action plan about a year ago. And at that point in time there was a slightly cleaner or substantially different proposal that would have involved the CPUC participating in the Energy Commission's process. And then adopting the Energy Commission's determination of need for use in its CPCN process.

Two of the Commissioners at the PUC objected to that provision in the energy action plan. And subsequently voted against the plan, and that provision was substantially rewritten, as well. But my recollection is that they said at the time, and I may have this mixed up, it was either all of the lawyers and most of the ALJs or most of the lawyers and all of the ALJs at the Public Utilities Commission agreed that the Commission could not pre-commit to a need determination and still extend procedural due process to the parties participating in the CPCN.

So, my personal view is that this is a dog that is not going to hunt. But, I look forward to seeing a copy of the comments you file.

MS. ARMI: Well, thank you. I'm heartened to hear that perspective. And your comments actually reflect very well the comments that we're going to be submitting tomorrow.

PRESIDING MEMBER GEESMAN: I was afraid

of that.

(Laughter.)

PRESIDING MEMBER GEESMAN: Other comments?

MR. FLYNN: If you don't mind, I'll sit down.

PRESIDING MEMBER GEESMAN: Please so.

MR. FLYNN: I can organize my thoughts a little better that way. Just remind me -- take too long.

PRESIDING MEMBER GEESMAN: Turn the green light on.

MR. FLYNN: I actually have a few slides. I'd indicated I'd returned to the way I thought that PG&E or the PTOs and the ISO and the CEC could work on this RMR reduction for load pockets situation.

And maybe if we could skip the first slide I want to return to that later; we'll go to the next one. This is excerpted from an ISO management report to the board. The blue is the PG&E RMR requirement; the red or maroon, whatever, is the SCE and the beige at the top if the SDG&E RMR requirement and how it's changed over time.

And I believe -- Dave, correct me if I'm wrong -- but when you talk about a load pocket I think practically all of the SDG&E is in what would be called their load pocket. And about 4000 of that 7400 megawatts of PG&E RMR is in the Bay Area load pocket.

Maybe we can go on to the next slide. But that's basically an indication of what I had said earlier.

I guess what I really want to focus on is the fact that at least for the Bay Area this is not a small issue. In some ways it's computationally simple compared to some of the more important and esoteric, hard-to-calculate benefits of transmission.

You may also know that the ISO, to their credit, tried to encompass this idea of retirement of old plants into a generation standard to be adopted by the planning standards subcommittee. And if you look at the current draft of that that's just about to be approved, you'll see that there's a footnote on the bottom with regard to the need to study all these retirements of these old units that, you know, you're not going to do it all at once.

When you look at the Bay Area and you

think about the number of plants that fit into that category, both based on that table and on the good work that the CEC is doing, we're talking about, you know, essentially the effect of doubling. Well, of doubling the load, you know. You're going from having to serve 10,000 megawatts with 6000 megawatts of transmission and 4000 megawatts of generation to, in the extreme, you know, serving all 10,000 megawatts with transmission.

So the various combinations of generators to look at, to try to identify the transmission projects that would go with the ability to not have that generation. And I want to point out that in terms of the technical studies the load flow doesn't know whether that generator's not there because it's been retired beyond anybody's control, or whether it's not there because we want to reduce it for RMR savings. I mean that technical part of the work is consistent or is useful or more than one purposes.

But I guess what I want to get back to in terms of where is the CEC's role, I think there's a lot of study work that needs to be done.

PG&E has indicated they will at least start on that. It's unclear how far they'll get this year in their annual planning cycle.

The ISO is doing a phase two of the San Francisco Peninsula long-term study. I've been pushing them to make that broader in terms of a long-term study for the Greater Bay Area. It remains to be seen how far we'll get there.

But those are two ongoing planning efforts that will take a lot of resources and a lot of time by both PG&E and the ISO. And I'm not at all proposing that the CEC step in the middle of that and try to duplicate what they're doing.

What I am proposing is once you've done those technical studies and now you've got to make that tradeoff of the RMR costs versus the transmission projects that gets identified, I think that's clearly a nice spot for the CEC to contribute to this major effort.

I'll just say that I believe that to a large extent, although the ISO Staff tries to be very open, the planning staff does a great job of being open with their planning process, once you mention numbers their attorneys say, oh, you can't talk about it.

So, I do know both from struggling with trying to get outage rates out of the ISO and trying to get costs, that despite what the staff wants to do, they are hampered in terms of their ability to really have an open and complete exposition of the alternatives before the public. I believe the CEC somehow finds a way to do that. And I think -- so that's the sales job in terms where the CEC's role is. Not to do the massive amount of work that PG&E and the ISO is proposing to undertake, but to come in at the rear end of that and try to do the RMR savings, which I think follows on nicely from the work that you're completing now with regard to looking at retirements.

I would just like to back up and take one more minute, so I don't impact people's ability to get home and see the final of the NCAA tournament. But if we go back one more slide, that was really put in there initially to try to motivate you to think about looking at additional transmission into load pockets.

But I want to use it for another purpose, and basically that was done in the 2002/2012 outlook by the CEC Staff. They had developed a -- just a very sophisticated XCEL spreadsheet to look at the probabilities. To essentially model the whole WSCC system with regard to they had to simplify the load pockets, or the load regions I should -- I use that terminology too much -- load regions within the WSCC, and simplify the transmission representation.

But they do a very sophisticated job with regard to representing both the outages rates and the transmission between those areas; the outage rates of the units and a probablistic profile on peak load.

And I'm not saying these are the right numbers. I'm saying the tool that was utilized here can be a very important tool as we go forward.

Gary DeShazo mentioned the fact that the ISO would like to see and like to convince WSCC how to go about probablistic planning. Well, I sat through the months and months where the planning standards subcommittee at the ISO tried to develop some probablistic standards. They tried to take it beyond just probability standards to value based transmission.

They never got there. They couldn't get a consensus between the PTOs and the ISO as to how to go about that. The one benefit that came out of that that there was a Bay Area generation outage standard that PG&E did when they recognized the more likelihood of multiple generation units being out in the San Francisco Bay area at the same time.

I'm convinced that this type of tool is a very important tool. And it can lead, if it's utilized and the numbers are displayed, can lead over time to at least a gradual change of deterministic planning process into more of a reliability type of process.

The reason I wanted to bring it up today is I believe the CEC Staff has some models and some expertise that they can be a big benefit in this.

And more specifically, as the planning standard subcommittee has tried to re-evaluate the standards for the Bay Area based on more recent data, we have found that some of the data that the ISO could not share with me has been shared with the CEC. And I know they're trying to work through how they can do some study work and present some results without being in violation of that confidentiality requirement.

But that's just another area where I believe that the CEC Staff has the expertise, and sounds like you have the motivation that you could provide some help in terms of moving the state away from deterministic planning to probablistic planning.

I would also like to mention deliverability was mentioned, and there's a fellow on Gary's staff that has done some really good work, as far as I'm concerned, on the analytical side of what deliverability really means. And I would submit to you that -- and he evidently gives credit to PJM in terms of developing the tools. But I would submit to you that their initial proposal on how they would determine whether a system was sufficient to deliver generation to load looks a lot like the way that the CEC Staff has looked at the probability of being able to serve load reliably in the various sub areas within the state.

Thank you.

PRESIDING MEMBER GEESMAN: Thank you. Other comments? Yes, sir.

MR. SANDOVAL: Good afternoon; my name is Juan Carlos Sandoval. I represent Imperial Irrigation District. We are a utility located in southeastern California. We are pretty much located in the middle of all the action, the transmission corridor between Arizona and California.

And I give my compliments to this effort. We have seen four years of all these problems and would like to participate in a solution to them.

I have a few comments, you know. We strongly support, you know, the initiative for long-range land use planning, you know. We have seen internally the need to a change in the policy to allow us to secure, you know, the transmission corridors and the transmission sites.

Also a change would help us in the environmental regulations, you know, just to allow to secure this land.

The other thing is the joint, you know, you can modify the -- or allow for this joint use projects. In the past we saw the lack of the regional planning. And obviously now that we have this process is in place, you know, now that some of the companies like ourselves, we have identify the need for increased transmission capability. We would like to have the ability to -- the capability to participate in some transmission projects.

PRESIDING MEMBER GEESMAN: Have you done that previously on a joint basis?

MR. SANDOVAL: Yes, we are co-owners in SWPL.

PRESIDING MEMBER GEESMAN: Okay.

MR. SANDOVAL: And right now we are actively participating, you know, we're sponsoring the desert southwest transmission project; it's a 500 kV line from Blythe to Devers.

PRESIDING MEMBER GEESMAN: Um-hum.

MR. SANDOVAL: So we are in conversations with Edison for the PV-Devers number two line.

As well as we are participating, you know, we want to be part of the solution, you know. We talking conversations with San Diego Gas and Electric for the 500 kV line from Ivy to Ramona, you know, Escondido, wherever is. And we'd like to participate in that project.

Also the situation that we have -- we

have about 500 megawatts of geothermal generation in our area, and we've got power to Edison, you know. There's potential for an additional 200 megawatts of generation, geothermal generation that we can participate. And we'll deliver that power to California.

Thank you.

PRESIDING MEMBER GEESMAN: Thank you. Other comments? Yes, sir.

DR. GALPERIN: Mark Galperin, CERC. You considering long-term planning for transmission. You're thinking of long-term plans. And doing so, we need to think of transmission efficiency, which needs to have some legislative incentives and support.

In terms of degrees of transmission losses and degrees demand for right-of-way. And this is question and suggestion. If such incentives are foreseen already then I'd like to have a referral to it, and that's it. I'll be glad to read it.

And if not, then a suggestion. I can't imagine that considering planning for couple decades this Committee should (inaudible) transmission efficiency. If not, be concern of utilities because according to current legislation, if I'm correct, this is kind of end user problem. Because whatever -- transmission, end user pays.

And we have ways to decrease losses during transmission. We have ways to decrease the amount right away, significant, practically -- but not a big concern.

I want to bring attention of this meeting to this problem. And I would kindly ask you in the agenda of other meeting of your considerations, if it's not happened yet.

PRESIDING MEMBER GEESMAN: Well, I guess the one thing that I would want to have a better understanding of probably from our legal staff more than anyone else, is the extent to which this isn't an area subject to the exclusive jurisdiction of the Federal Energy Regulatory Commission. I don't know that the state really has a constructive role to play in establishing efficiency standards for an interstate grid when and if that is likely to be legally preempted by FERC.

We have a lot of work to do in areas that aren't legally preempted by FERC where I think it's probably more productive for us to stay focused.

DR. GALPERIN: Yes, I think that we have plenty extensive grid within the state which should be effective, as well as interstate.

PRESIDING MEMBER GEESMAN: Um-hum.

DR. GALPERIN: And I am concerned first of California grid.

PRESIDING MEMBER GEESMAN: Well, the bulk system is all operated pursuant to a FERC tariff, so I think that legal threshold was crossed some time ago. And I think at least the question that your comments raise in my mind is whether there's any role whatsoever for one of the 50 states to attempt to prescribe standards for the operation of that bulk system.

And it's just simply a question I'd need more legal guidance from our staff on.

DR. GALPERIN: But is it -- just a question. Is it in power of the state legislators to establish any incentive for utilities for savings of energy --

PRESIDING MEMBER GEESMAN: The Public Utilities Commission does have that ability.

DR. GALPERIN: You can do something,

not, I mean --

PRESIDING MEMBER GEESMAN: Right.

DR. GALPERIN: And the same with right-of-way. I heard ecologists, that we so suffer that transmission line consumes so many lands of California and so on, so forth. We have real ways to decrease this demand. And it's matter only, again, technology consideration.

So, again, unless some incentives would be introduced, it won't go further --

PRESIDING MEMBER GEESMAN: No, we conduct one of the largest R&D programs in the country relating to more efficient use of the transmission grids. So there's a lot of work being done here and with a variety of stakeholders on researching ways in which to improve the efficient operation of the grid.

I may have misunderstood your comments about prescriptive standards. But we do have a lot of work underway on an R&D basis.

DR. GALPERIN: I didn't say anything about prescriptive standards, I said about increasing efficiency of transmission.

Thank you.

PRESIDING MEMBER GEESMAN: Thanks.

Anyone else?

I want to thank you again for your contributions today. This has been extraordinarily valuable. I think we'll yield a very rich transcript, which I intend to spend a considerable amount of time with.

And I would certainly invite your written comments, as well.

Thanks, again. We'll be adjourned.

(Whereupon, at 3:56 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 9th day of April, 2004.